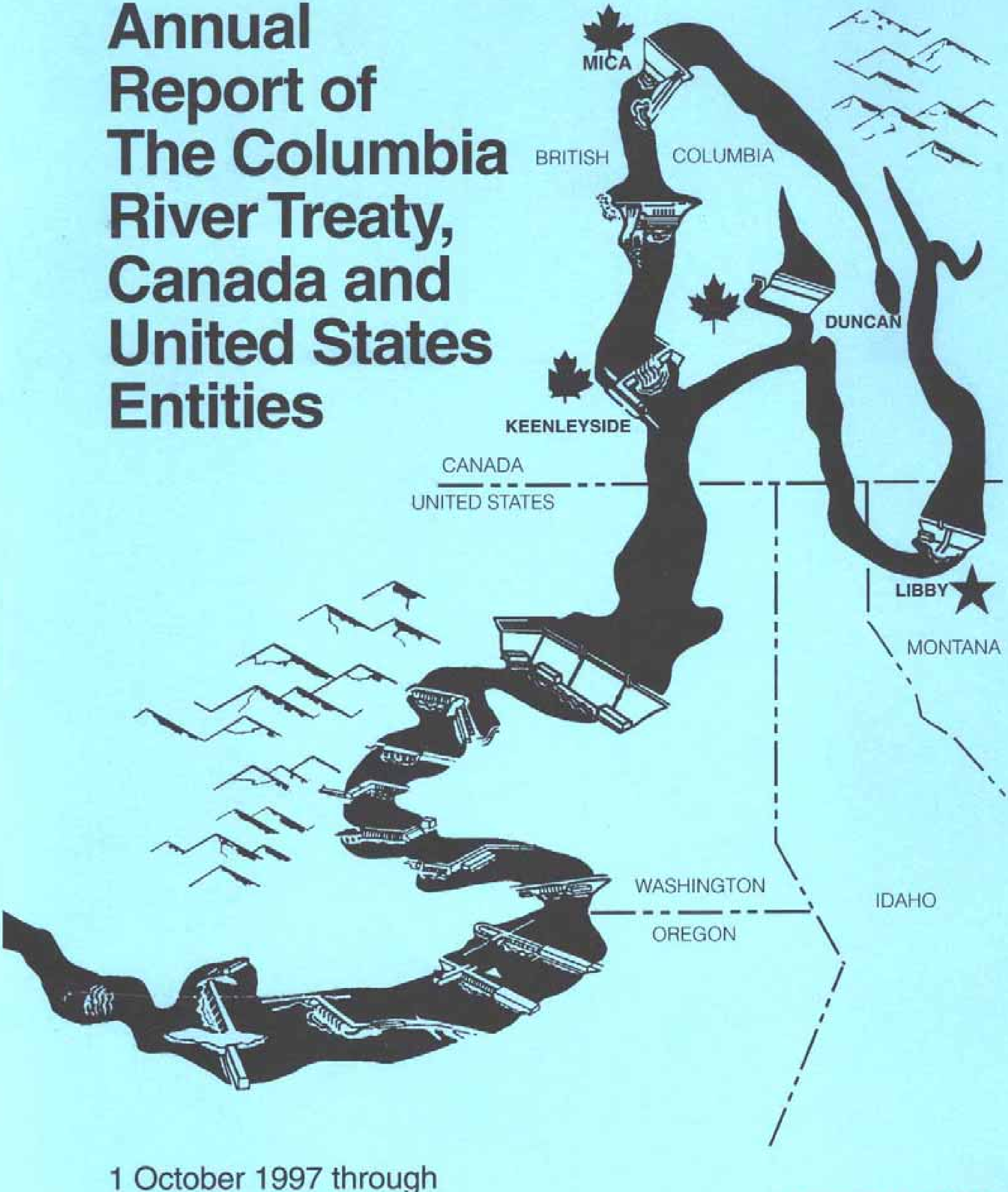
Annual Report of The Columbia River Treaty, Canada and United States Entities



1 October 1997 through
30 September 1998

November 1998

ANNUAL REPORT OF
THE COLUMBIA RIVER TREATY
CANADIAN AND UNITED STATES ENTITIES

FOR THE PERIOD

OCTOBER 1, 1997 - SEPTEMBER 30, 1998

Executive Summary

General

The Canadian Treaty projects, Mica, Duncan, and Arrow were operated during the reporting period according to the 1997-98 and 1998-99 Detailed Operating Plans, the Flood Control Operating Plan, and several supplemental operating agreements described below. Throughout the year, Libby was operated according to the Flood Control Operating Plan, as amended. During a portion of the year, the Corps operated Libby for power purposes according to the Pacific Northwest Coordination Agreement (PNCA) Actual Energy Regulation (AER). During the remainder of the year, Libby was operated according to the terms and conditions of the Biological Opinions as specified in the U.S. Army Corps of Engineers Records of Decision, and according to supplemental operating agreements described below. As recorded in the Detailed Operating Plans covering the current year's operation, the Entities could not agree on the operation of Libby.

During the reporting period, the Entities were not able to agree on an AOP and Determination of Downstream Power Benefits (DDPB), as required by the Treaty, due to the dispute regarding Libby. However, in anticipation of potential settlements, the Entities did complete two sets of studies and draft 2002-03 AOP/DDPB documents, with and without the inclusion of the Libby minimum flows for sturgeon and salmon. In addition, the Entities have draft AOP/DDPB documents, with and without the effect of Libby minimum flows for sturgeon and salmon, for the 2000-01 and 2001-02 operating years.

On April 1, 1998, the first return of Canadian Entitlement power to British Columbia since 1968 began flowing at the existing interconnections between BPA and B.C. Hydro. The initial amount delivered, not including transmission losses and scheduling adjustments, was 50.0 average MW at rates up to 111.1 MW. On August 1, 1998, the Canadian Entitlement return increased to 50.8 average MW at rates up to 136.8 MW.

Entity Agreements

Agreement approved by the Entities during the period of this report includes:

- Columbia River Treaty Entity Agreement on Adjustment of Transmission Losses to Reflect Step-Up Transformer Losses on U.S. Columbia River Federal Projects, signed March 9, 1998.
- Columbia River Treaty Entity Agreement on Aspects of the Delivery of the Canadian Entitlement for April 1, 1998, through September 15, 2024, signed March 26, 1998, and effective upon a diplomatic exchange of notes between the United States and Canada relating to Entitlement Disposal in the United States.
- Columbia River Treaty Entity Agreement on the Detailed Operating Plan for Columbia River Storage for August 1, 1998, through July 31, 1999, signed July 30, 1998.

Operating Committee Agreements

Agreements approved by the Operating Committee include:

- Agreement on Implementation of the Arrow Local Method for Treaty Storage for Operating Year 1997-98 Among the Columbia River Treaty Operating Committee, the Bonneville Power Administration, and the British Columbia Hydro and Power Authority, dated February 2, 1998.
- Columbia River Treaty Operating Committee Agreement on Modification of Scheduling Procedures for Aspects of Delivery of the Canadian Entitlement, April 1998 through February 1999, dated March 30, 1998.
- Columbia River Treaty Operating Committee Agreement on Treatment of Transmission Losses Relative to the Canadian Entitlement, dated April 1, 1998.
- Agreement among the Columbia River Treaty Operating Committee, the Bonneville Power Administration and British Columbia Hydro and Power Authority on the Operation of Canadian Treaty and Libby Storage Reservoirs and Exchanges of Power for the Period August 1, 1998, through January 17, 1999, signed July 31, 1998.
- Columbia River Treaty Operating Committee Agreement on the Operation of Canadian Treaty and Libby Storage Reservoirs for the Period August 1, 1998, through April 30, 1999, signed August 19, 1998.

- Columbia River Treaty Operating Committee Agreement on the Operation of Treaty Storage for Enhancement of Mountain Whitefish Spawning for the Period of September 8, 1998, through July 31, 1999, signed September 8, 1998.

System Operation

The coordinated system filled to 99.09 percent of capacity by July 31, 1997, in the Pacific Northwest Coordination Agreement (PNCA) Actual Energy Regulation (AER) operating plan. The AER hydro-system monthly power model demonstrates an operation for U.S. projects that meets firm load and all non-power requirements. Included in the AER is the Treaty Storage Regulation (TSR) operation for Canadian Treaty storage. The TSR is developed based on the Assured Operating Plan (AOP) and Detailed Operating Plan (DOP) for Canadian storage. Once the TSR is completed for Canadian Storage it is input to the AER as a fixed parameter. Since the AER showed the coordinated system being 99.09 percent full on July 31, 1997, first year firm load carrying capability (FLCC) was adopted for the 1997-98 operating year. Actual storage capacity was filled to 95.9 percent of full. Due to above average streamflows throughout the year, the system generally operated to Operating Rule Curve or Flood Control Curve for the entire period.

The January 1, 1998, water supply forecast for the Columbia River at The Dalles (January-July) was 86.4 million acre-feet (Maf), or 82 percent of the 1961-90 average. January rainfall was above normal and the February water supply forecast increased to 95.2 Maf at The Dalles. Rainfall was generally below normal in February, March, and April, and as a result the May final water supply forecast at The Dalles had decreased to 89.1 Maf. May was extremely wet, and the precipitation in the basin above The Dalles was 201 percent of normal for the month. June precipitation was also above normal, and the actual January-July observed runoff was 104.1 Maf, or 98 percent of average. The peak daily average flow observed at The Dalles was 442,200 cubic feet per second (cfs) on May 30, 1998.

The Lower Columbia River flow was regulated for juvenile fish between April 20 and August 31 based on recommendations of the "Technical Management Team" (TMT) consisting of representatives from five U.S. Federal agencies. State fishery agencies and Indian tribes also provided input at the TMT meetings. This information was usually provided through the Fish Passage Center (FPC). The TMT's Executive and Technical groups make recommendations to the two operating agencies (Corps of Engineers and Bureau of Reclamation) on flow and operations to optimize passage conditions for juvenile and adult anadromous salmons in the lower Snake and Columbia Rivers in accordance with the National Marine Fisheries Service's Biological Opinion (BiOp). Each year, the TMT will also prepare a Water Management Plan to meet various fishery, flow, reservoir operation, and other objectives. On May 14, 1998 a Supplemental Biological Opinion was issued by NMFS in response to listing of three steelhead species in the Columbia River.

Coordinated System storage energy in the AER reached a level of 99.39 percent of full on July 31, 1998. This value was used to determine the Firm Load Carrying Capability (FLCC), with first-year FLCC being adopted for the 1998-99 operating year. The actual reservoir refill was 99.39 percent of full.

From April 1, 1997, through March 31, 1998, generation at downstream projects in the United States delivered to the Columbia Storage Power Exchange (CSPE) participants under the Canadian Entitlement Exchange Agreement, was approximately 246 average megawatts at rates up to 471 megawatts. From April 1 through July 31, 1998, the delivery was 215 average megawatts, at rates up to 416 megawatts. All CSPE power was used to meet Pacific Northwest loads.

From April 1, 1997, through March 31, 1998, the Canadian Entity delivered 2.8 average megawatts of energy and no dependable capacity to the U.S. Entity under the Canadian Entitlement Purchase Agreement. Between April 1, 1998, and July 31, 1998, the Canadian Entity delivered 3.7 average megawatts of energy and 0.4 megawatts of dependable capacity to the U.S. Entity under the CSPE/CEPA.

Treaty Project Operation

The Treaty projects, Duncan, Mica, and Arrow were operated throughout the year in accordance with the 1997-98 Detailed Operating Plan, the Flood Control Operating Plan, and several Operating Committee agreements on nonpower uses throughout the year. Libby reservoir was operated in accordance with the Flood Control Operating Plan, as amended by the U.S. Army Corps of Engineers (USACE) "Review of Flood Control, Columbia River Basin, Columbia River & Tributaries Study, CRT-63" June 1981. During the fall of 1997, Libby was operated for power requirements according to the PNCA AER. By December 31, 1997, and during the remainder of the operating year, Libby operated for storage and releases required for endangered White Sturgeon and Salmon as recommended by both the U.S. Fish and Wildlife Service and the National Marine Fishery Service Biological Opinions. As recorded in the Detailed Operating Plan for the current year, the Entities could not agree on operations of Libby.

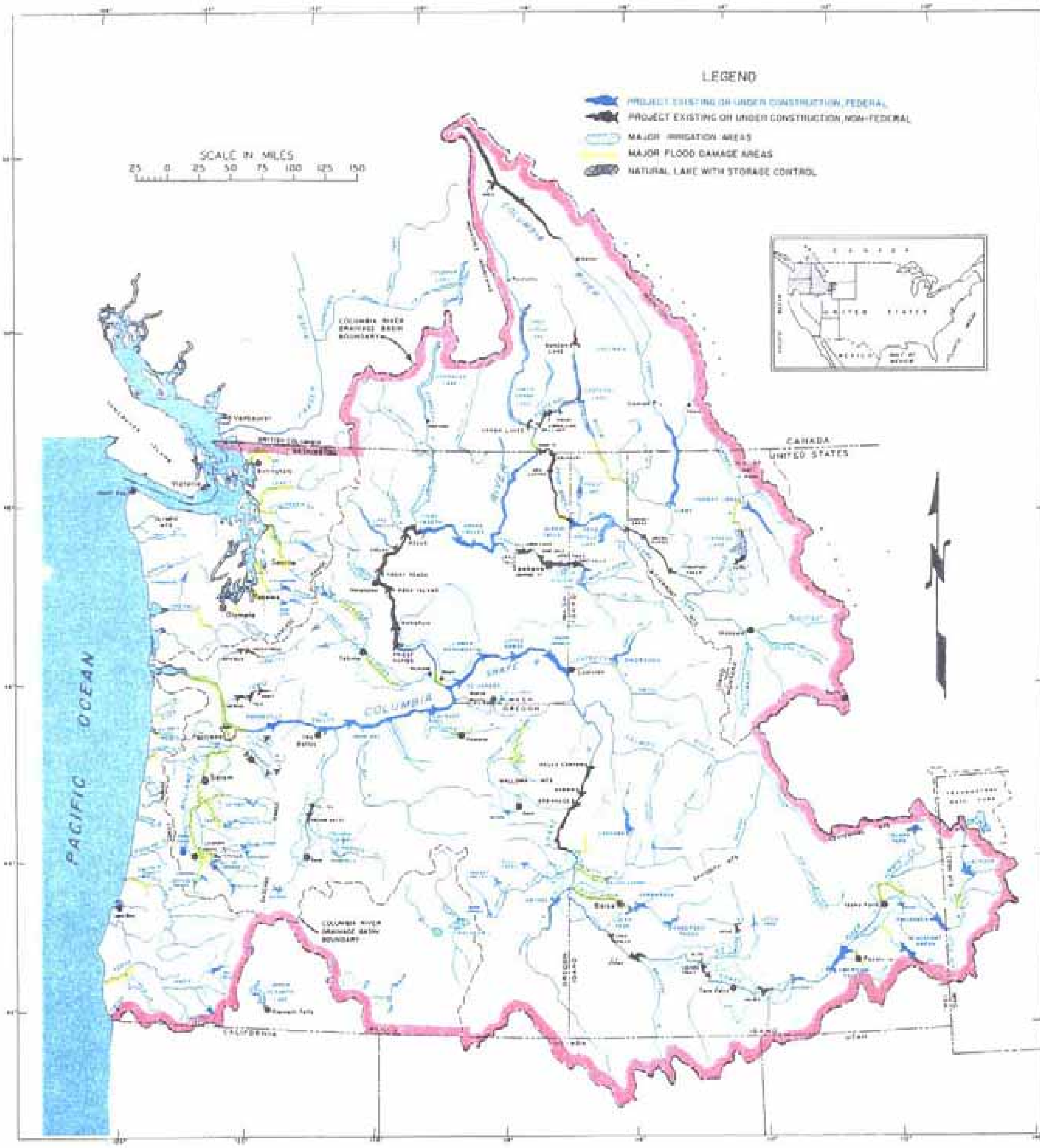
Mica Treaty storage was 6.7 Maf on July 31, 1997, and with continued storing, reached 7.0 Maf or 100 percent full content on August 12, 1996. The actual reservoir elevation reached a high of elevation 2475.4 feet (0.4 feet above full) on September 1. By December 31, Treaty storage was drafted to 4.9 Maf and the observed reservoir level had dropped to elevation 2439.8 feet. Treaty storage reached the lowest level on April 30, 1998 at 0.03 Maf. The reservoir reached its lowest level for the 1997-98 water year, elevation 2386.4 feet, on April 23, 1998. From then on, Mica's Treaty storage refilled, reaching 93 percent of full (6.5 Maf) on July 31, 1998. The maximum level for 1998, elevation 2466.6 (8.4 feet below full), was reached on August 10, 1998.

The Arrow Treaty storage account started the 1997-98 operating year (August 1, 1997) at 7.1 Maf, or 100 percent full. The reservoir was drafted to elevation 1427.7 feet on December 31, 1997, with a Treaty storage of 6.0 Maf or 84 percent of full. Arrow reached its lowest level of the year elevation 1386.2 feet on April 1, 1998. Arrow Treaty storage reached its annual minimum on March 31 at 1.1 Maf or 15 percent full. With low discharges in April and May, and the start of the spring freshet, Arrow filled to elevation 1397.2 feet by April 30. April 5 through July 5, outflows were held between 12 and 20 kcfs to ensure rainbow trout would not spawn at high river levels. The Arrow Reservoir reached its highest level of the year on July 31, 1998, at elevation 1438.6 feet. The Arrow Treaty storage reached 100 percent full on July 29, 1998. To minimize spill at the Kootenay River plants in Canada, the Operating Committee Agreement permitted a Libby-Arrow water transfer agreement in 1998. Under the agreement, Libby volume releases were reduced by a total of 107 ksfd in July and August, and an equal amount of water was released from Arrow Reservoir. This water will be returned to Arrow Reservoir in the September to January 17 period. In July, outflows were increased and the Arrow outflow peaked at 72.2 kcfs on August 6. During August, increased outflows drafted Arrow to elevation 1437.37 feet. Further drafting to elevation 1433.20 feet was done by September 30.

Duncan reservoir over filled by the end of the 1996-97 operating year with a reservoir level of elevation 1892.1 feet on July 31, 1998. The project passed inflow for the remainder of August to maintain the reservoir near full pool. During September to December, Duncan was used to adjust the Kootenay Lake level and by December 31, Duncan reservoir had drafted to elevation 1859.4 feet (58 percent of full). Duncan reached its lowest level during the 1997-98 operating year of elevation 1795.9 feet, on March 24, 1998. Minimum release during May to early July helped refill the reservoir to elevation 1892.0 by August 12, 1998. With outflows increased to near inflow, the project maintained near full pool. On September 1, outflow was increased to begin drafting Duncan and filling Kootenay Lake. By September 30, 1998, Duncan had been drafted to elevation 1877.95 feet.

During the 1997-98 operating year, Lake Koocanusa began August 1997 at elevation 2453.56 feet (5.40 feet below full pool). The first 13 days of August 1997 Libby released 10 kcfs and continued to fill. By August 12, 1997, Lake Koocanusa was at elevation 2454.82 feet, 4.18 feet from full. When the salmon managers would have requested outflow be increased to full powerhouse outflow of 24.5 kcfs for downstream salmon flow augmentation, the Libby/Arrow swap agreement was initiated by the Canadian Entity and the Corps increased outflow to only 14.5 kcfs. The Arrow project released the additional 10 kcfs for the remainder of August. Ultimately Libby did not release water down to its interim draft limit of elevation 2439.0 feet because of the agreement to store approximately 190 ksfd of Arrow Treaty water. In return, Arrow delivered the 190 ksfd in August. The Libby project was drafted to 2411.71 feet by the end of December, which is within one foot of the Upper Rule Curve. Project releases in the spring considered flood control, sturgeon flows, refill for recreation and salmon flows. Only one sturgeon pulse was provided in June since the water supply forecast in early May was below 80% of normal. This operation was coordinated with the U.S. Fish and Wildlife Service. Libby reached its maximum level of 2458.32 (0.68 feet from full) on July 17, 1998. The end of August elevation in 1998, after the draft for salmon, was 2443.87 feet, 15.13 feet from full.

COLUMBIA RIVER AND COASTAL BASINS



1998 Report of the Columbia River Treaty Entities
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1998 Report of The Columbia River Treaty Entities
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I Introduction

This annual Columbia River Treaty Entity Report is for the 1998 Water Year, October 1, 1997, through September 30, 1998. It includes information on the operation of Mica, Arrow, Duncan, and Libby reservoirs during that period with additional information covering the reservoir system operating year, August 1, 1997, through July 31,1998. The power and flood control effects downstream in Canada and the United States are described. This report is the thirty-second of a series of annual reports covering the period since the ratification of the Columbia River Treaty in September 1964.

Duncan, Arrow, and Mica reservoirs in Canada and Libby reservoir in the United States of America were constructed under the provisions of the Columbia River Treaty of January 1961. Treaty storage in Canada is operated for the purposes of flood control and increasing hydroelectric power generation in Canada and the United States of America. In 1964, the Canadian and the United States governments each designated an Entity to formulate and carry out the operating arrangements necessary to implement the Treaty. The Canadian Entity is the British Columbia Hydro and Power Authority (B.C. Hydro). The United States Entity is comprised of the Administrator of the Bonneville Power Administration (BPA) and the Division Engineer of the Northwestern Division, U.S. Army Corps of Engineers (ACE).

The following is a summary of key features of the Treaty and related documents:

1. Canada is to provide 15.5 million acre-feet (Maf) of usable storage. This has been accomplished with 7.0 Maf in Mica, 7.1 Maf in Arrow and 1.4 Maf in Duncan.
2. For the purpose of computing downstream power benefits the U.S. base system hydroelectric facilities will be operated in a manner that makes the most effective use of the improved streamflow resulting from operation of the Canadian storage.
3. The U.S. and Canada are to share equally the downstream power benefits generated in the U.S. resulting from operation of the Canadian storage.
4. The U.S. paid Canada a lump sum of the $64.4 million (U.S.) for one half of the present worth of expected future flood control benefits in the U.S. resulting from operation of the Canadian storage.
5. The U.S. has the option of requesting the evacuation of additional flood control space above that specified in the Treaty, for a payment of $1.875 million (U.S.) for each of the first four requests for this "on-call" storage.
6. The U.S. had the option (which it exercised) to construct Libby Dam with a reservoir that extends 42 miles into Canada and for which Canada agreed to make the land available in return for downstream power benefits in Canada.

7. Both Canada and the United States have the right to make diversions of water for consumptive uses. In addition, since September 1984 Canada has had the option of making for power purposes specific diversions of the Kootenay River into the headwaters of the Columbia River.

8. Differences arising under the Treaty which cannot be resolved by the two countries may be referred to either the International Joint Commission (IJC) or to arbitration by an appropriate tribunal.

9. The Treaty shall remain in force for at least 60 years from its date of ratification, September 16, 1964.

10. In the Canadian Entitlement Purchase Agreement of August 13, 1964, Canada sold its entitlement to downstream power benefits to the United States for 30-years beginning at Duncan on April 1, 1968, at Arrow on April 1, 1969, and at Mica on April 1, 1973.

11. The Canadian Entitlement Purchase Agreement began expiring on April 1, 1998 and that power component owned by Canada attributable to Duncan is being returned to Canada at the U.S. – Canada border. The component attributable to Arrow will begin to be returned April 1, 1999, while the last part attributable to the construction of Mica will begin to be returned April 1, 2003, thus ending the Purchase Agreement.

12. Canada and the U.S. are each to appoint Entities to implement Treaty provisions and are to jointly appoint a Permanent Engineering Board (PEB) to review and report on operations under the Treaty.

II Treaty Organization

Entities

There was one meeting of the Columbia River Treaty Entities (including the Canadian and U.S. Entities and Entity Coordinators) during the year on the morning of February 3, 1998 in Portland, Oregon. The members of the two Entities at the end of the period of this report were:

UNITED STATES ENTITY
Ms. Judith A. Johansen, Chair
Administrator & Chief Executive Officer
Bonneville Power Administration
Department of Energy
Portland, Oregon

Brigadier General Robert H. Griffin, Member
Division Engineer
Northwestern Division
Army Corps of Engineers
Portland, Oregon

CANADIAN ENTITY
Mr. Brian R. D. Smith, Chair
British Columbia
Hydro and Power Authority
Vancouver, British Columbia

Ms. Johansen succeeded Mr. John S. Robertson effective June 8, 1998, who in turn had succeeded Mr. Randall Hardy as Chairman as of October 1, 1997.

The Entities have appointed Coordinators, Secretaries and two joint standing committees to assist in Treaty implementation activities that are described in subsequent paragraphs. The primary duties and responsibilities of the Entities as specified in the Treaty and related documents are to:

1. Plan and exchange information relating to facilities used to obtain the benefits contemplated by the Treaty.

2. Calculate and arrange for delivery of hydroelectric power to which Canada is entitled and the amounts payable to the U.S. for standby transmission services.

3. Operate a hydrometeorological system.

4. Assist and cooperate with the Permanent Engineering Board in the discharge of its functions.

5. Prepare hydroelectric and flood control operating plans for the use of Canadian storage.

6. Prepare and implement detailed operating plans that may produce results more advantageous to both countries than those that would arise from operation under assured operating plans.

Additionally, the Treaty provides that the two governments by an exchange of diplomatic notes may empower or charge the Entities with any other matter coming within the scope of the Treaty.

The Entities met once during the year, on the morning of February 3, 1998.

Entity Coordinators & Secretaries

The Entities have appointed members of their respective staffs to serve as Coordinators and Secretaries to act as focal points on Treaty matters within their organizations.

The members are:

UNITED STATES ENTITY COORDINATORS

Mark W. Maher, Coordinator
Vice President, Generation Supply
Bonneville Power Administration
Portland, Oregon

James E. Crews, Coordinator
Director, Engineering & Technical Services
Northwestern Division
Army Corps of Engineers
Portland, Oregon

Dr. Anthony G. White, Secretary to
the U.S. Entity
Regional Coordination
Resource Optimization
Bonneville Power Administration
Portland, Oregon

CANADIAN ENTITY COORDINATOR

T. J. (Tim) Newton, Coordinator
Vice President, Market Development
POWEREX
Vancouver, British Columbia

Douglas A. Robinson, Secretary to
the Canadian Entity
Power Planning
Power Supply
BC Hydro and Power Authority
Burnaby, British Columbia

Mr. Crews was appointed to succeed Ms. Kristine Allaman, effective August 16, 1998, who in turn was appointed to succeed Mr. John Velehradsky effective October 1, 1997.

Columbia River Treaty Operating Committee

The Operating Committee was established in September 1968 by the Entities, and is responsible for preparing and implementing operating plans as required by the Columbia River Treaty, making studies and otherwise assisting the Entities as needed. The Operating Committee consists of eight members as follows:

UNITED STATES SECTION

Gregory K. Delwiche, BPA, Co-Chair
William E. Branch, ACE, Co-Chair
Cynthia A. Henriksen, ACE
John M. Hyde, BPA

CANADIAN SECTION

Ralph D. Legge, B.C. Hydro, Chair
Kenneth R. Spafford, B.C. Hydro
Kelvin C. Ketchum, B.C. Hydro
Dr. Thomas K. Siu, B.C. Hydro

Mr. Ketchum was appointed to succeed Mr. Henry Mark effective April 1, 1998.

There were six meetings of the Operating Committee during the year. The dates, places, and number of persons attending those meetings were:

Date	Location	Attendees
November 20, 1997	Vancouver, B.C.	20
January 14, 1998	Portland, OR	16
March 12, 1998	Edmonds, B.C.	21
May 12, 1998	Portland, OR	18
July 22, 1998	Mica Creek, B.C.	19
September 17, 1998	Portland, OR	17

The Operating Committee coordinated the operation of the Treaty storage in accordance with the current hydroelectric and flood control operating plans. This aspect of the Committee's work is described in following sections of this report, which have been prepared by the Committee with the assistance of others. During the period covered by this report, the Operating Committee completed the August 1, 1998 through July 31, 1999, Detailed Operating Plan (DOP).

Columbia River Treaty Hydrometeorological Committee

The Hydrometeorological Committee was established in September 1968 by the Entities and is responsible for planning and monitoring the operation of data facilities in accord with the Treaty and otherwise assisting the Entities as needed. The Committee consists of four members as follows:

UNITED STATES SECTION	CANADIAN SECTION
Nancy L. Stephan, BPA, Co-Chair	Eric C. Weiss, B.C. Hydro, Chair
Peter F. Brooks, ACE, Co-Chair	Don J. Druce, B.C. Hydro, Member

Mr. Druce succeeded Mr. Heiki Walk as Canadian Member as of October 1, 1997.

There were two meetings of the Hydrometeorological Committee, on October 28, 1997 and on April 14, 1998. The first meeting (No. 43) was hosted by BCH in Vancouver, BC and the second (No. 44) was hosted by the Corps in Portland, OR.

At the October 28, 1997, meeting, the 11 attendees discussed the new CAFE UNIX-based computer reporting system, a LAN-based replacement for the old Columbia Basin Telecommunications system, updating of the hydromet station list to distinguish between Treaty and support stations, and plans of BC Environment to replace snow pillows with snow courses. The committee reviewed 1997 reservoir operations, water supply forecasts, and various forecasting issues at Revelstoke and Duncan. A project to convert to the U.S. National Weather Service River Forecast System (NWSRFS) from SSARR is expected to take up to three years to complete.

At the April 14, 1998, meeting, the 8 attendees received a presentation on the SNOTEL system operations and costs, and on River Forecast Center forecasts. The principal action item from this meeting was an identified need to update the 1968 "Terms of Reference" which created the Committee, and a need to distinguish between Treaty and Support hydromet stations.

Permanent Engineering Board

Provisions for the establishment of the Permanent Engineering Board (PEB) and its duties and responsibilities are included in the Treaty and related documents. Thr ~embers of the PEB are presently:

UNITED STATES SECTION	CANADIAN SECTION
Steven L. Stockton, Chair San Francisco, Ca.	Daniel R. Whelan, Chair Ottawa, Ontario
Ronald H. Wilkerson, Member Missoula, Montana	John Allan, Member Victoria, British Columbia
Charles M. Hess, Alternate nominee Washington, D.C.	Prad Kharé, Alternate Victoria, British Columbia
George E. Bell, Alternate Portland, Oregon	David E. Burpee, Alternate Ottawa, Ontario
Richard J. DiBuono, Secretary Washington, D.C.	David E. Burpee, Secretary Ottawa, Ontario

Under the Treaty, the PEB is to assemble records of flows of the Columbia River and the Kootenay River at the international boundary. It is also to report to both governments if there is deviation from the hydroelectric or flood control operating plans, and if appropriate, include recommendations for remedial action. Additionally, the PEB is to:

- assist in reconciling differences that may arise between the Entities;
- make periodic inspections and obtain reports as needed from the Entities to assure that Treaty objectives are being met;
- prepare an annual report to both governments and special reports when appropriate;
- consult with the Entities in the establishment and operation of a hydrometeorological system; and
- investigate and report on any other Treaty related matter at the request of either government.

The Entities continued their cooperation with the PEB during the past year by providing copies of Entity agreements, operating plans, downstream power benefit computations, Operating Committee agreements, corrections to hydrometeorological documents, and the annual Entity report to the Board for their review. The annual joint meeting of the PEB and the Entities was held on the morning of February 3, 1998, in Portland, Oregon.

PEB Engineering Committee

The PEB has established a PEB Engineering Committee (PEBCOM) to assist in carrying out its duties. The members of PEBCOM at the end of the period of this report were:

UNITED STATES SECTION

Richard J. DiBuono, Chair
Washington, D.C.
Robert K Johnson, Member
Golden, CO
Earl E. Eiker, Member
Washington, D.C.
James D. Barton, Member
Portland, OR
D. James Fodrea, Member
Boise, ID
Stephan J. Wright, Alternate Member
Washington, D.C.

CANADIAN SECTION

Roger S. McLaughlin, Chair
Victoria, British Columbia
David E. Burpee, Member
Ottawa, Ontario
Larry N. Adamache, Member
Vancouver, British Columbia
Myriam Boudreault, Member
Ottawa, Ontario
Dr. G. Bala Balachandran, Member
Victoria, British Columbia

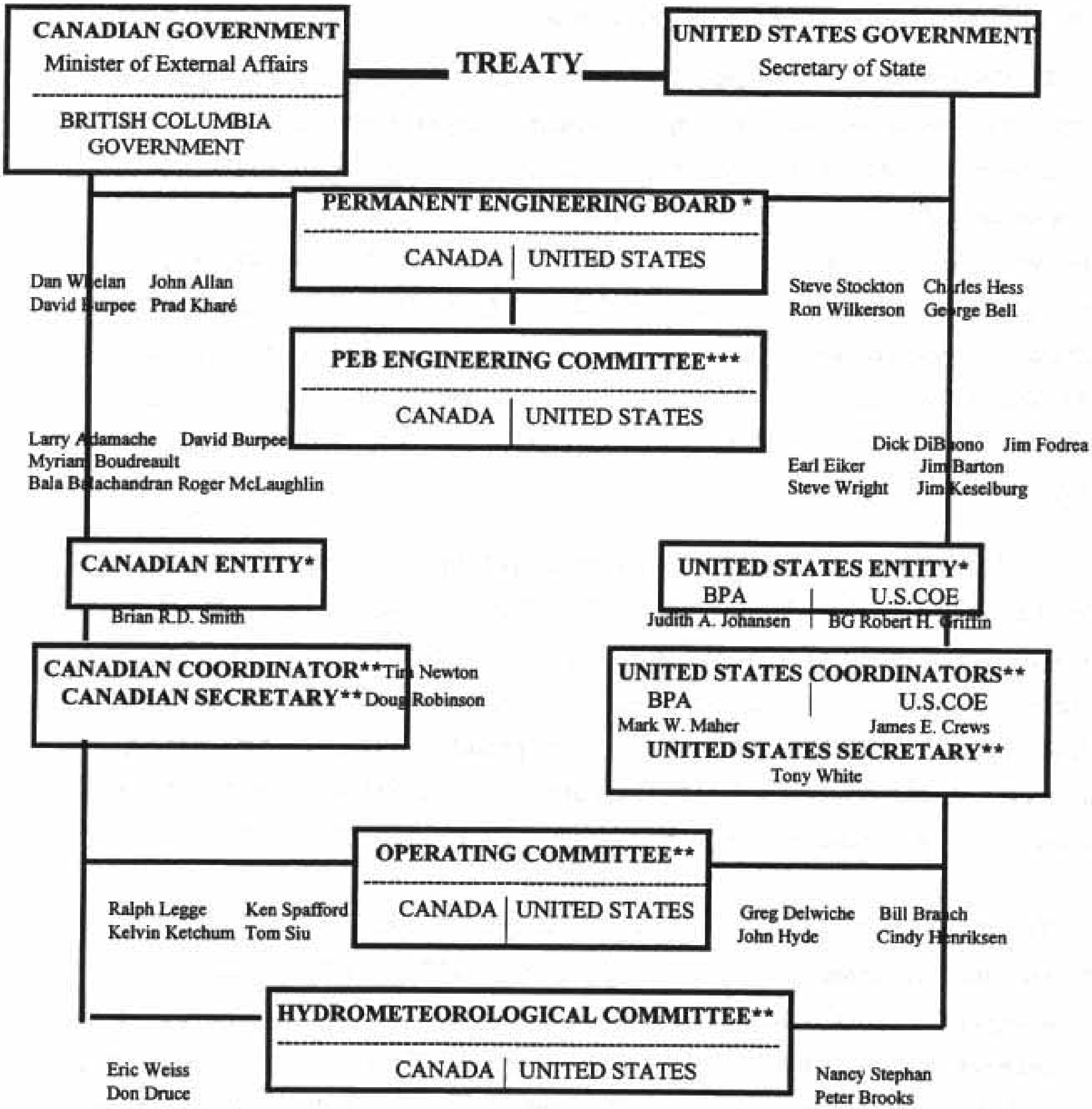
PEBCOM met with the operating committee on October 7, 1997, in Vancouver, B.C. and on February 4, 1998 in Portland, Oregon.

International Joint Commission

The International Joint Commission (IJC) was created under the Boundary Waters Treaty of 1909 between Canada and the U.S. Its principal functions are rendering decisions on the use of boundary waters, investigating important problems arising along the common frontier not necessarily connected with waterways, and making recommendations on any question referred to it by either government. If the Entities or the PEB cannot resolve a dispute concerning the Columbia River Treaty, that dispute may be referred to the IJC for resolution.

The IJC has appointed local Boards of Control to insure compliance with IJC orders and to keep the IJC informed. There are three such boards west of the continental divide. These are the International Kootenay Lake Board of Control, the International Columbia River Board of Control, and the International Osoyoos Lake Board of Control. The Entities and the IJC Boards conducted their Treaty activities during the period of this report so that there was no known conflict with IJC orders or rules.

COLUMBIA RIVER TREATY ORGANIZATION



* ESTABLISHED BY TREATY
** ESTABLISHED BY ENTITY
*** ESTABLISHED BY PEB

III Operating Arrangements

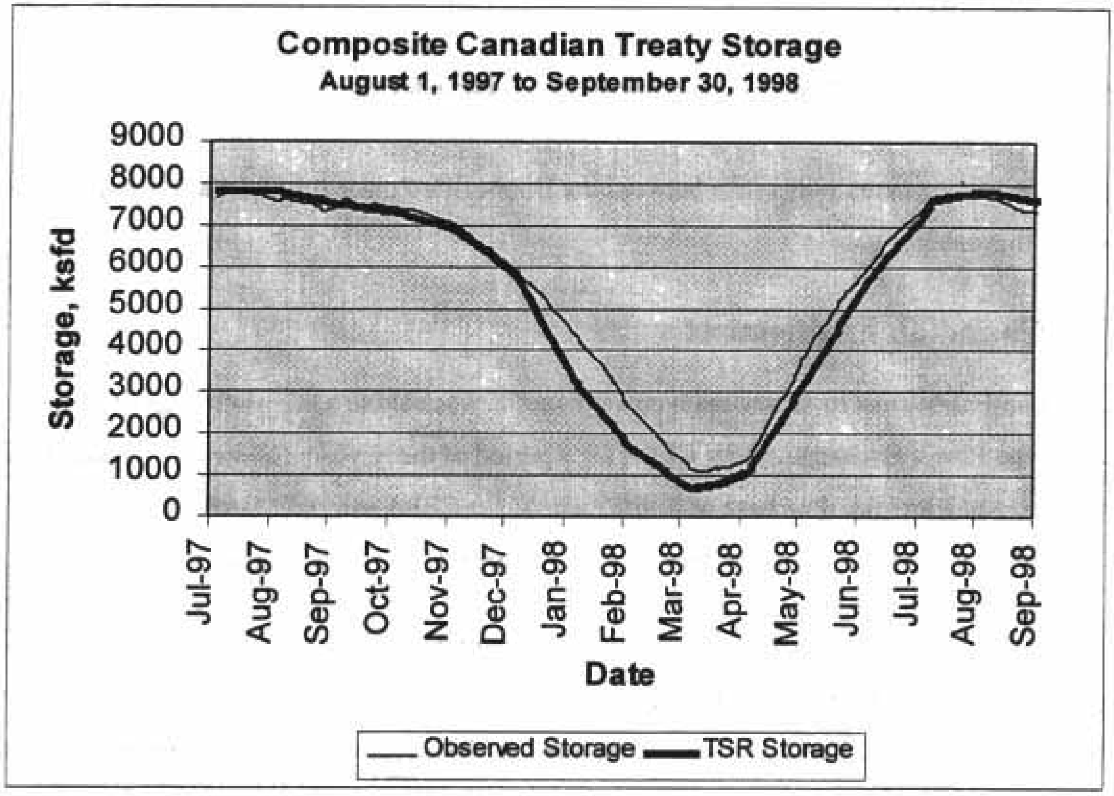
Power and Flood Control Operating Plans

The Columbia River Treaty requires that the reservoirs constructed in Canada be operated pursuant to flood control and hydroelectric operating plans developed thereunder. Annex A of the Treaty stipulates that the United States Entity will submit flood control operating plans (FCOP). Annex A also says that the Canadian Entity will operate in accordance with flood control storage diagrams or any variation which the Entities agree will not be adverse to the desired aim of the flood control plan. Annex A also provides for the development of hydroelectric operating plans six years in advance to furnish the Entities with an Assured Operating Plan (AOP) for Canadian storage. In addition, Article XIV.2.k of the Treaty provides that a Detailed Operating Plan may be developed to produce results more advantageous. The Protocol to the Treaty provides further detail and clarification of the principles and requirements of the Treaty.

The "Principles and Procedures for the Preparation and Use of Hydroelectric Operating Plans" dated December 1991 together with the "Columbia River Treaty Flood Control Operating Plan" dated October 1972, establish and explain the general criteria used to develop the DOP and operate Treaty storage during the period covered by this report. The flood control Storage Reservation Diagram for Libby contained in the 1972 Flood Control Plan, was amended by agreement of the Operating Committee to that contained in the U.S. Army Corps of Engineers (ACE) "Review of Flood Control, Columbia River Basin, Columbia River & Tributaries Study, CRT-63", dated June 1981.

The planning and operation of Canadian Treaty Storage as discussed on the following pages is for the operating year, August 1 through July 31. The operation of Canadian Treaty storage is determined by the Treaty Storage Regulation (TSR). The TSR is developed based upon the critical rule curves, and Power Discharge Requirements for all projects in the Pacific Northwest that were developed for the 1997-98 Assured Operating Plan (AOP). The resultant rule curves for Canadian projects may be updated slightly to be consistent with current requirements upon agreement of both Entities. The Canadian Storage operations resultant in the TSR are fixed and become input to the Pacific Northwest Coordination Agreement Actual Energy Regulation (AER). U.S. storage projects are operated to the principles defined in the Pacific Northwest Coordination Agreement procedures and the resultant Actual Energy Regulations (AER). Most of the hydrographs and reservoir charts in this report are for a 13-month period, July 1997 through July 1998.

The following chart demonstrates the composite Canadian Treaty Operating Rule Curve (ORC) as computed from the Treaty storage Regulation (TSR). The TSR was on in ECC (Energy Content curve) during the entire period.



Assured Operating Plan

The Assured Operating Plans, dated October 1992 and October 1994, established Operating Rule Curves and other operating criteria for Duncan, Arrow, and Mica during the 1997-98 and 1998-99 operating years, respectively. The Operating Rule Curves provided guidelines for draft and refill. They were derived from Critical Rule Curves, Assured Refill Curves, Upper Rule Curves, and Variable Refill Curves, consistent with flood control requirements, as described in the 1991 Principles and Procedures document. The Flood Control Storage Reservation Curves were established to conform to the Flood Control Operating Plan of 1972.

Determination of Downstream Power Benefits

For each operating year, the Determination of Downstream Power Benefits resulting from Canadian Treaty storage is made six years in advance in conjunction with the Assured Operating Plan. For operating year 1998-99 the estimate of benefits resulting from operating plans designed to achieve optimum operation in both countries was less than that which would have prevailed from an optimum operation in the United States only. The Entities agreed that, in accordance with Sections 7 and 10 of the Canadian Entitlement Purchase Agreement (CEPA), the United States was entitled to receive:

- 2.8 average megawatts of energy and no dependable capacity during the period April 1, 1997 through March 31, 1998, and
- 3.7 average megawatts of energy and 0.4 megawatts of dependable capacity during the period April 1, 1998 through March 31, 1999.

Suitable arrangements were made between the Bonneville Power Administration and B.C. Hydro for delivery of this energy.

Return of Canadian Entitlement

Canadian Entitlement to downstream power benefits was sold to a nonprofit organization, the Columbia Storage Power Exchange, under CEPA for a period of thirty years following completion of each Canadian storage project. Purchase of Entitlement under CEPA expired March 31, 1998, for Duncan, and will expire March 31, 1999, for Arrow and March 31, 2003, for Mica.

On April 1, 1998 Entitlement power began being returned to Canada at the U.S.-Canada border, over existing power lines, as established by the November 20, 1996, Entity Agreement. For the period April 1, 1998, through July 31,1998, the amount returned for Duncan was 50 average megawatts of energy at a peak of 111 megawatts of capacity. For the period beginning August 1, 1998, and ending March 31, 1999, the amount returned will be 50.8 average megawatts of energy at a peak of 136.8 megawatts of capacity.

Detailed Operating Plan

During the period covered by this report, the Operating Committee used the August 1, 1997, through July 31,1998, "Detailed Operating Plan for Columbia River Treaty Storage" (DOP), dated August 1997 and the August 1, 1998, through July 31, 1999, DOP, signed July 30, 1998, and dated August 1998, to guide storage operations. These DOP's established criteria for determining the Operating Rule Curves and other operating data for use in actual operations. The DOP used the AOP critical rule curves for Canadian Projects. The Variable Refill Curves and flood control requirements subsequent to January 1, 1998, were determined on the basis of seasonal volume runoff forecasts during actual operation. The Operating Committee, on a weekly basis throughout the year, directed the regulation of the Canadian storage.

Entity Agreements

During the period covered by this report, three joint U.S.-Canadian arrangements were approved by the Entities. The following tabulation indicates the date each of these was signed and gives a description of the agreement:

Date Agreement Signed by Entities	Description
March 9, 1998	Columbia River Treaty Entity Agreement on Adjustment of Transmission Losses to Reflect Step-Up Transformer Losses on U.S. Columbia River Federal Projects.
March 26, 1998	Columbia River Treaty Entity Agreement on Aspects of the Delivery of the Canadian Entitlement for April 1, 1998 through September 15, 2024, to be effective upon an exchange of diplomatic notes between the United States and Canada.
July 30, 1998	Columbia River Treaty Entity Agreement on the Detailed Operating Plan for Columbia River Storage for August 1, 1998 through July 31, 1999.

Operating Committee Agreements

During the period covered by this report, the Operating Committee approved five joint U.S.-Canadian agreements. The following tabulation indicates the dates they were signed, gives descriptions of the agreements, and cites the authorities:

Date Agreement Signed by Committee	Description	Authority
February 2, 1998	Agreement on Implementation of the Arrow Local Method for Treaty Storage For Operating Year 1997-98 Among the Columbia River Treaty Operating Committee, the Bonneville Power Administration, and the British Columbia Hydro and Power Authority	Detailed Operating Plan, August 1, 1997, through July 31, 1998, approved July 30, 1997, and dated August 1997
March 30, 1998	Columbia River Treaty Operating Committee Agreement on Modification of Scheduling Procedures for Aspects of Delivery of the Canadian Entitlement, April 1998 through February 1999	Entity Agreement on Aspects of the Delivery of the Canadian Entitlement for April 1, 1998, through September 24, 2024, dated November 20, 1996
April 1, 1998	Columbia River Treaty Operating Committee Agreement on Treatment of Transmission Losses Relative to Delivery of the Canadian Entitlement	Entity Agreement on Aspects of the Delivery of the Canadian Entitlement for April 1, 1998, through September 24, 2024, dated November 20, 1996
July 31, 1998	Agreement among the Columbia River Treaty Operating Committee and the Bonneville Power Administration and British Columbia Hydro and Power Authority on the Operation of Canadian Treaty and Libby Storage Reservoirs and Exchanges of Power for the Period August 1, 1998, through 17 January 1999	Detailed Operating Plan, August 1, 1998, Through July 31, 1999, Approved July 30, 1998, and dated August 1998
August 19, 1998	Columbia River Treaty Operating Committee Agreement on Operation of Canadian Treaty and Libby Storage Reservoirs for the Period August 1, 1998, through April 30, 1999	Detailed Operating Plan, August 1, 1998, Through July 31, 1999, Approved July 30, 1998, and dated August 1998
September 8, 1998	Columbia River Treaty Operating Committee Agreement on Operation of Treaty Storage for Enhancement of Mountain Whitefish for the Period September 8, 1998, through July 31, 1999	Detailed Operating Plan, August 1, 1998 through July 31, 1999, approved July 30, 1998, and dated August 1998

Long Term Non-Treaty Storage Contract

An Entity Agreement dated July 9, 1990, approved the contract between B.C. Hydro and BPA relating to the initial filling of non-Treaty storage, coordinated use of non-Treaty storage, and Mica and Arrow refill enhancement. The Operating Committee, in accordance with that agreement, monitored the storage operations made under this Agreement throughout the operating year to insure that they did not adversely impact operation of Treaty storage.

IV Weather and Streamflow

Weather

This year's weather was influenced by the peak and waning effects of the strongest and longest-lasting El Niño to occur this century. The temperatures of the tropical and North Pacific Ocean, due to El Niño, were sufficient to move the storm-steering, upper level atmospheric weather systems and their jet streams away from their typical seasonal positions. In most summers a high pressure system resides in the Gulf of Alaska blocking storms from entering the Northwest and in the winter the Gulf is dominated by a large low pressure system that, with its counter-clockwise circulation, steers storms into the Northwest. This year, however, the high and low pressure systems were less intense and located west of their typical positions which allowed warm and wet air masses in the Northwest and kept temperatures low because of the additional cloud cover. The re-positioned winter low pressure systems allowed the jet stream to split, with one branch of the jet, directing storms, into central British Columbia and the other branch directing storms into central and southern California. This left the Northwest relatively warm and dry, except during periods when the split flow pattern broke down.

July 1997 weather was dominated by a steady flow of moist air into the Northwest, producing showers that resulted in nearly twice the normal monthly rainfall above Grand Coulee, and with the additional cloud cover, lower than normal temperatures. Late in July, and lasting through August, a broad high pressure ridge formed on the coast bringing drier and warmer air into the region and allowing only three-fourths the normal August rainfall, even with the extra rainfall from the passage of the remnants of tropical storm *Ignacio* on the 20th.

The weather patterns shifted again in September allowing more and stronger storms to penetrate the Northwest producing more than 150% of normal rainfall in the Columbia Basin above Grand Coulee. In October, following the passage of former tropical storm *Ginger*, winter began to make its presence known with heavy precipitation, cooler temperatures, and the beginning on the winter snowpacks. November and December saw another adjustment in the weather patterns with basin temperatures averaging 2.1°F above normal and average monthly precipitation ranging from half to two-thirds of normal during these typically precipitation and snow accumulation months. January saw a turn of the previous two-month's weather by being warm (4.3°F above normal) and wet (105% of normal above Grand Coulee and 113% above Castlegar). Several fronts and deep troughs moved across the basin during the first 10 days, followed at mid-month by a warm air mass with several frontal systems which dumped the month's heaviest precipitation, followed by showers that continued to the month's end. February saw yet another change in the weather patterns with the split flow directing most storm energy into northern California and the southern edge of the Columbia Basin. Basin temperatures averaged 3.3°F above normal and precipitation above Grand Coulee was only 43% of normal.

March saw a return to normal weather patterns with rapidly moving storms, showers, and brief periods of clear weather. Basin temperatures averaged 1.1°F above normal and precipitation above Grand Coulee averaged 105% of normal. The Pacific Northwest Seasonal Precipitation Accumulation is shown in Chart 1. Upper air low-pressure troughs with cold air, clouds, and rainfall from Alaska dominated the Pacific Northwest the first three weeks of April. Warm temperatures and an unusually strong thermal low engulfed the region in 80-90°F weather during the last week that initiated fast and furious snowmelt, resulting in minor flooding in eastern Idaho. This thermal low was slowly pushed eastward and was replaced by cooler and wetter Aleutian air that brought the wet cycle back to the Northwest by May 3 with an upper atmospheric trough extending from Alaska to the Oregon coast. This helped guide front after front into the region for the rest of the month. Precipitation in the Columbia Basin above Grand Coulee averaged 176% of normal. The resultant accumulated snowpack across the January through May period is shown in Chart 2. June saw a continuation of the wet spring with rainfall averaging 134% of normal in the basin above Grand Coulee while in July hot moist weather dominated the basin above Grand Coulee with temperatures averaging 3.5°F above normal and rainfall averaging 140% of normal.

1997-98 Precipitation Index at The Dalles

Month	Precipitation			Month	Precipitation	
(1997)	(in.)	(%)		(1998)	(in.)	(%)
Jul	2.07	190		Jan	3.69	125
Aug	0.97	78		Feb	1.44	69
Sep	2.03	145		Mar	1.90	100
Oct	2.66	162		Apr	1.42	89
Nov	1.63	60		May	3.66	201
Dec	1.54	51		Jun	2.31	128
				Jul	1.45	133
				Aug	0.47	38
			July-June	Annual	25.32	109

Temperature departure and precipitation for each month are shown in Charts 3 through 5.

Streamflow

The observed inflow and outflow hydrographs for the Canadian reservoirs for the period July 1, 1997, through July 31,1998, are shown on Charts 6 through 8. Chart 9 shows Libby hydrographs. Observed flows with the computed unregulated flow hydrographs for the same 13-month period for Kootenay Lake, Columbia River at Birchbank, Grand Coulee, and The Dalles are shown on Charts 10, 11, 12, and 13 respectively. Chart 14 is a hydrograph of observed and two unregulated flows at The Dalles during the April through July 1998 period, including a plot of flows occurring if regulated only by the Treaty reservoirs.

Composite operating year unregulated streamflows in the basin above The Dalles were near normal, far below the last years well above average streamflows. May was the high month during the spring runoff, being in the 127% of normal range. The August 1997 through July 1998 runoff for The Dalles was 143 Maf 105% of the 1961-90 average. The peak regulated discharge for the Columbia River at The Dalles was 442,200 cfs on May 30, 1998. The 1997-98 monthly unregulated (natural) streamflows and their percent of the 1961-90 average monthly flows are shown in the following table for the Columbia River at Grand Coulee and at The Dalles. These flows have been corrected to exclude the effects of regulation provided by storage reservoirs.

	Columbia River at Grand Coulee in cfs		Columbia River at The Dalles in cfs	
Time Period	Natural Flow	Percent of Average	Natural Flow	Percent of Average
Aug 97	115,490	110	157,270	114
Sep 97	86,900	135	133,150	138
Oct 97	92,850	192	146,520	171
Nov 97	60,570	125	114,930	126
Dec 97	40,150	95	88,750	94
Jan 98	40,510	99	96,750	98
Feb 98	42,460	91	108,760	94
Mar 98	62,110	105	145,430	103
Apr 98	114,970	99	225,580	101
May 98	323,370	123	535,600	127
Jun 98	235,880	72	390,280	79
Jul 98	155,820	81	220,240	86
Operating Year	114,260	101	196,940	105
Water Year	112,990	101	189,590	100

Seasonal Runoff Forecasts and Volumes

Observed 1998 April through August runoff volumes, adjusted to exclude the effects of regulation of upstream storage, are listed below for eight locations in the Columbia Basin:

Location	Volume In 1000 Acre-Feet	Percent of 1961-90 Average
Libby Reservoir Inflow	5,838	92
Duncan Reservoir Inflow	1,987	97
Mica Reservoir Inflow	11,023	96
Arrow Reservoir Inflow	20,747	89
Columbia River at Birchbank	37,279	92
Grand Coulee Reservoir Inflow	37,860	82
Snake River at Lower Granite Dam	25,008	109
Columbia River at The Dalles	90,094	97

Forecasts of seasonal runoff volume, based on precipitation and snowpack data, were prepared in 1998 for a large number of locations in the Columbia River Basin and updated each month as the season advanced. Table 1 lists the April through August volume inflow forecasts for Mica, Arrow, Duncan, and Libby projects and for unregulated runoff for the Columbia River at The Dalles. Also shown in Table 1 are the actual volumes for these five locations. The forecasts for Mica, Arrow, and Duncan inflow were prepared by B.C. Hydro. The forecasts for the lower Columbia River and Libby inflows were prepared by the National Weather Service and River Forecast Center in cooperation with the Corps of Engineers, National Resource Conservation Service, Bureau of Reclamation and B.C. Hydro. The April 1, 1998, forecast of January through July runoff for the Columbia River above The Dalles was 90.8 Maf and the actual observed runoff was 92.1 Maf.

The following tabulation summarizes monthly forecasts since 1970 of the January through July runoff for the Columbia River above The Dalles compared with the actual runoff measured in millions of acre-feet (Maf). The average January-July runoff for the 1961-1990 period is 105.9 Maf.

The Dalles Volume Runoff Forecasts in Maf (Jan-Jul)

Year	Jan	Feb	Mar	Apr	May	June	Actual
1970	82.5	99.5	93.4	94.3	95.1		95.7
1971	110.9	129.5	126.0	134.0	133.0	135.0	137.5
1972	110.1	128.0	138.7	146.1	146.0	146.0	151.7
1973	93.1	90.5	84.7	83.0	80.4	78.7	71.2
1974	123.0	140.0	146.0	149.0	147.0	147.0	156.3
1975	96.1	106.2	114.7	116.7	115.2	113.0	112.4
1976	113.0	116.0	121.0	124.0	124.0	124.0	122.8
1977	75.7	62.2	55.9	58.1	53.8	57.4	53.8
1978	120.0	114.0	108.0	101.0	104.0	105.0	105.6
1979	88.0	78.6	93.0	87.3	89.7	89.7	83.1
1980	88.9	88.9	88.9	89.7	90.6	97.7	95.8
1981	106.0	84.7	84.5	81.9	83.2	95.9	103.4
1982	110.0	120.0	126.0	130.0	131.0	128.0	129.9
1983	110.0	108.0	113.0	121.0	121.0	119.0	118.7
1984	113.0	103.0	97.6	102.0	107.0	114.0	119.1
1985	131.0	109.0	105.0	98.6	98.6	100.0	87.7
1986	96.8	93.3	103.0	106.0	108.0	108.0	108.3
1987	88.9	81.9	78.0	80.0	76.7	75.8	76.5
1988	79.2	74.8	72.7	74.0	76.1	75.0	73.7
1989	101.0	102.0	94.2	99.5	98.6	96.9	90.6
1990	86.5	101.0	104.0	96.0	96.0	99.5	99.7
1991	116.0	110.0	107.0	106.0	106.0	104.0	107.1
1992	92.6	89.1	83.5	71.2	71.2	67.8	70.4
1993	92.6	86.5	77.3	76.6	81.9	86.1	88.0
1994	79.7	76.3	78.1	73.2	75.5	76.4	75.0
1995	101.0	99.6	94.3	99.6	99.6	97.9	104.0
1996	116.0	122.0	130.0	126.0	134.0	141.0	139.3
1997	138.0	145.0	142.0	149.0	153.0	159.0	159.0
1998	86.4	95.2	91.7	90.8	89.1	101.0	104.0

V Reservoir Operation

General

The 1997-98 operating year began with slightly above normal precipitation in October across the basin. By the end of December precipitation had dwindled and the basin wide accumulated precipitation was below normal. The accumulated precipitation remained below normal through April. The May final water supply forecast, which was developed during the first ten days of May and included precipitation through April 30, was 89.1 Maf at The Dalles for the January through July period. This was 84% of average for the period 1961-1990. May was a very wet month where precipitation was 176% of normal above Grand Coulee, 235% of normal above Lower Granite, and 201% of normal above The Dalles. When the June final water supply forecast was developed during the first ten days of June, this additional May precipitation was included. The June final water supply forecast had increased dramatically to 101.0 Maf at The Dalles for the period January through July. June also had above normal precipitation, and the observed runoff at The Dalles for the period January through July was 104.0 Maf, or 98% of average.

During the April 10 - August 31 salmon flow augmentation period, U.S. projects were used to augment flows at Lower Granite and McNary. The National Marine Fisheries Service's Biological Opinion, released in early March 1995, listed flow objectives that were variable based on runoff volume forecasts. The flow objectives were:

- Lower Granite, 85,000-100,000 cfs during April 10 - June 20, and 50,000-55,000 cfs during June 21- August 31.
- McNary, 220,000-260,000 cfs during April 20- June 30, and 200,000 cfs during July 1-August 31.

Provision for adjusting flow objectives based on runoff volume forecasts was based on a sliding scale such that in 1998 Lower Granite flow objectives were 90,000 cfs and 50,600 cfs for the two periods. The McNary spring objective was 228,000 cfs for the first period; the second period is set at 200,000 cfs and does not vary with runoff forecasts.

The computation of the flow objectives at Lower Granite are based on the May final water supply forecast, which was 17.3 Maf at Lower Granite for the April through July period, which is 80% of average. The spring flow objective at McNary was based on the May final water supply forecast of 89.1 Maf at the Dalles for the January through July period. Although May and June experienced above normal precipitation, the flow objectives are not updated in those months. The flow objectives at

Lower Granite were exceeded in the spring and summer. The observed outflow at Lower Granite for the period April 10 through June 20 was 113,000 cfs and June 20 to August 31 was 53,000 cfs. At McNary the Spring period flow objective was exceeded. The average observed outflow for the period April 20 through June 30 was 289,000 cfs, and the observed flow from July 1 through August 31 was 173,000 cfs.

There were no significant flood control activities during late 1997 through the 1998 freshet. In late May 1998 there were some minor restrictions in project operations for flood control and the stages at both Vancouver, Washington, and Portland harbor did not reach flood stage.

Mica Reservoir

As shown in Chart 6, the Mica Reservoir (Kinbasket Lake) level was at elevation 2471.1 feet on July 31, 1997, 3.9 feet below full pool elevation of 2475 feet. The corresponding Mica Treaty storage was 95% full at 3336.9 ksfd (6.7 Maf) on that date.

The local inflows into Mica reservoir averaged about 41 kcfs in August, reducing to 27 kcfs in September and about 5.6 kcfs by 1997 year end. Mica Treaty storage continued to fill during August, reaching full storage of 3529.2 ksfd (7.0 Maf) on August 12. As a result of a 1 in 200 year rainfall event, high inflows filled the Mica reservoir to full pool on October 2 and required a spill of 59 ksfd during October 2-5. The inflows started to recede on October 4 and the reservoir started to drop as turbine discharges exceeded inflows. The Mica Treaty underrun of 130 ksfd on August 31 increased in September and October, decreasing somewhat in November with the year end underrun at 467 ksfd on December 31, 1997. The reservoir level remained above elevation 2460 feet until late November.

Actual Mica discharges were fairly high through August 1997 and averaged 81% of the maximum turbine capacity. This corresponded to an average discharge of about 35 kcfs in August. Subsequent discharges averaged about 25 kcfs in September, 33 kcfs in October, 27 kcfs in November and about 35 kcfs in December. Over November and December, the reservoir drafted by 29.1 feet to an elevation of 2439.8 feet by year end. At that time the B.C. Hydro Non-Treaty Storage was about 680 ksfd; 60% of full, with Treaty storage at 2451.6 ksfd (4.9 Maf) 69 % of full.

In early January 1998, the inflows dropped off to below 1 kcfs, gradually increasing to an average of 5 kcfs between January and mid-April 1998 before the start of the spring freshet. Mica Powerhouse discharges for January averaged around 34.7 kcfs and the generation from Mica continued to decrease over winter 1998. The reservoir drafted by 30 feet over January and February, to elevation 2409.2 feet by February 28 with Treaty Storage at 1344.9 ksfd and Mica Treaty underrun of 43 ksfd on that date. The B.C. Hydro NTSA was at 714 ksfd at the end of February. During March and April, the Mica Reservoir was drafted by 21 feet and reached its lowest level for the 1997-98 year of 2386.4 feet on April 23, 1998, 2.8 feet higher than the low level in previous year. Mica Treaty storage reached a minimum of 15 ksfd (0.03 Maf) on April 30 with Mica flex at 513 ksfd.

In March and April, the Mica turbine discharges averaged about 21 kcfs reducing to an average 1.7 kcfs in May and 0.9 kcfs in June 1998. The corresponding plant generation was less than 5% of plant capacity during these months. With the start of the spring freshet in early May, Mica discharges remained low, and the reservoir refilled by 59 feet to elevation 2446 feet. At the end of May, the Mica Treaty underrun had been reduced to 479 ksfd. The Mica Treaty discharge was 10 kcfs for the months of May, June and July, allowing Treaty storage to refill to 3284 ksfd (6.5 Maf; 93% of full) by July 31. Local inflows were the highest in May, June and July averaging about 44, 43 and 49 kcfs, respectively. Actual Mica discharges during July averaged 21 kcfs, resulting in a Mica Treaty underrun of 363 ksfd and a reservoir elevation of 2463.5 feet by end of July 1998. The corresponding plant generation was about 45% of plant capacity in July 1998.

On August 10, 1998, the Mica Reservoir level reached a maximum elevation of 2466.6 feet before receding. Very high temperatures in August produced high inflows due to glacier melt. The Mica Treaty storage reached full at 3529 ksfd on August 13, 1998. The inflows dropped off to under 30 kcfs by the end of August 1998.

Revelstoke Reservoir

During the 1997-98 operating year, the Revelstoke project was operated generally as a run-of-river plant with the reservoir level maintained within 4.8 feet of its normal full pool elevation of 1880 feet. During the spring freshet, March through July, the reservoir was occasionally operated as low as elevation 1874.4 feet to provide additional operational space to control high local inflows.

Arrow Reservoir

As shown in Chart 7, the Arrow Reservoir level reached its maximum actual elevation of 1444.1 feet on July 31 with the Arrow Treaty storage reaching 100 percent full a day earlier on July 30, 1997. In comparison, the Mica Treaty storage filled on August 12. The maximum Treaty storage from the Canadian Projects was recorded on August 8, 1997, at 7792 ksfd. The reservoir continued to draft in August and reached an elevation of 1432.2 feet by the end of September, 3.8 feet higher than the previous year. The Arrow Treaty storage was 6.4 Maf or 90 percent full at the end of September.

Arrow discharges decreased over the autumn months from an average of 59 kcfs in September to 38 kcfs in November. The discharge increased to an average of 60 kcfs in December. Local inflows decreased from about 80 kcfs at the end of July, to 63 in August and to 42 by the 1997 year-end, still substantially greater than the previous year. The 1 in 200 year rainfall event in October resulted in high inflows late in the fall. The Arrow Reservoir drafted to elevation 1427.7 feet by December 31, 1997 with the Treaty storage at 3010 ksfd (6.0 Maf) or 84% of full on that date.

In late December 1997, B.C. Hydro requested that Arrow outflows be selectively reduced below Treaty requests to keep river levels at acceptable and maintainable levels during the whitefish spawning and emergence period from December 24 to January 21, 1998. BPA agreed to this under terms of the Non-Power Uses Agreement. Subsequently, in January, a minimum discharge of 53 kcfs at Keenleyside was established, reducing to 38 kcfs during last week of March and ramping down further to about 20 kcfs in April to meet objectives for rainbow trout spawning. In the transition from whitefish to rainbow trout protection, dropping the flows to 20 kcfs resulted in dewatering of some whitefish eggs. In the process of obtaining these flows, B.C. Hydro exercised its option to store up to 300 ksfd under a Provisional Draft Agreement over the first 16 days of January. This water was later released to assist with the U.S. Flow Augmentation operation. In addition a Provisional storage of 200 ksfd in Arrow from November 1997 was later released by both the Canadian and U.S. entities in spring and summer in accordance with agreements established to meet operational and fishery objectives. Arrow Reservoir continued to draft during the January to March period when the local inflows averaged 43 and 27 kcfs approximately.

In this operating year, the Columbia River Treaty Operating Committee agreed to use the 'Arrow Local' method, instead of the default 'Arrow Total' method for determining the treaty releases from January through July 1998. The 'Arrow Total' method and 'Arrow Local' method differ in two primary ways. The most significant difference is that the 'Arrow Total' method adjusts Arrow to compensate for Mica being re-operated to its Project Operating Criteria as indicated in the DOP, while in the 'Arrow Local' method Arrow is not required to adjust in response to Mica's re-operation. This results in the 'Arrow Local' method normally allowing additional draft of Arrow reservoir during the January to March period with a corresponding reduction in discharges for the April to July period. An additional difference is that the 'Arrow Total' method calculates the Variable Refill Curve (VRC) for Arrow using unregulated inflow to Arrow less the storage needed to refill Mica, while the 'Arrow Local' method calculates the VRC for Arrow using Mica's DOP release plus local inflow to Arrow, omitting the storage needed to refill Mica. In both cases, the Arrow reservoir is targeted to be treaty full on July 31.

Arrow Reservoir reached its lowest level for the year at 1386.2 feet on April 1, 1998. Arrow Treaty storage reached its minimum at 547 ksfd (1.1 Maf) or 15% of full at the end of March 1998. During April and early May, the Arrow discharge was kept at about 20 kcfs in an attempt to insure that rainbow trout would not spawn at higher river levels. A lower Arrow discharge in mid-May was possible because the backwater effects of higher Kootenay River flows helped to maintain suitable river levels on the Norn Creek Fan, a prime spawning location for rainbow trout. In consultation with the Canadian Fishery Agencies, an innovative 'Siphon Excavation Method' was applied as shown in the photograph on the next page to transfer rainbow trout eggs from redds in danger of being dewatered to temporary hatchery facility at the project. This proved more effective than the previous year's attempt to keep the redds wetted for a limited time using a pump and sprinkler system. Work is also currently underway to develop site-specific TGP guidelines through the studies of the spatial and temporal depth distribution of adult rainbow trout in the Columbia River.

Rainbow Trout Egg Excavation Study Siphon Excavation Method, Norms Creek Area - Columbia River Basin, April 1, 1998.

The Arrow fisheries operations were conducted under the terms of two Operating Committee agreements, "Operation of Treaty Storage for Enhancement of Whitefish Spawning for September 20, 1997, through April 30, 1998", and "Operation of Treaty Storage for Nonpower uses for January 1 through July 31, 1998". These agreements enabled the Arrow project flows to be adjusted to reduce impacts to whitefish and trout redds. With the low discharge in April and May, and the start of the spring freshet with high inflows in May, the Arrow Reservoir rose to elevation 1397.2 feet by April 30, 1421.1 feet by May 31, and 1434.4 feet by June 30, 1998. Arrow reservoir levels remained below the Treaty flood control curve levels throughout the operating year.

The Arrow discharge was increased substantially in July as Arrow Treaty storage neared full and the reservoir reached its highest elevation, 1438.6 feet, on July 31,1998. The Arrow discharge peaked at 72.2 kcfs on August 6, approximately three weeks later than the previous year. The Arrow Treaty storage content continued to fill and reached full (7.1 Maf) on July 29. With the increased Arrow discharges in late July and August, the Arrow Reservoir drafted to elevation 1437.4 feet by the end of August.

To minimize spill at the Canadian Kootenay River plants and maintain Koocanusa reservoir water levels in Canada for resident fish and recreation, the Canadian and U.S. Entities agreed to a Libby-Arrow water transfer in summer of 1998 as described in the Storage Transfer Agreement section later in this report.

Duncan Reservoir

As shown in Chart 8, the Duncan reservoir level was at elevation 1892.1 feet, slightly above full pool on 15 and July 30, 1997. The reservoir level exceeded the full pool slightly on several days in August and September as well. The reservoir remained within 1.0 feet of the full pool elevation of 1892.0 feet until September 1997 and slightly exceeded full Treaty storage on several days during July and August. By September 30, 1997, Duncan had been drafted to elevation 1889.8 feet.

During the month of September, Duncan discharged an average of 5.0 kcfs to maintain Kootenay Lake levels and Kootenay River flows. The project discharge averaged 4.2 kcfs in October, 4.9 in November and 6.0 in December. Higher discharges between mid-December to February were necessary to again support Kootenay Lake levels and flows. The Duncan Reservoir level was at elevation

1859.4 feet (58% of full) on December 31, 1997. The Duncan reservoir remained at or below the flood control curve throughout the operating year.

During January, the Duncan discharge was increased to about 8.2 kcfs. The reservoir was drafted throughout February to mid-March and reached its lowest level for the year at elevation 1795.9 feet (1.7 feet above empty) on March 24, 1998.

The Duncan discharge was reduced to minimum, 100 cfs, during most of May to begin refilling the reservoir. The reservoir reached elevation 1844.3 feet by May 31 and elevation 1872.2 feet by June 30. Duncan remained on minimum discharge until July 5. At that time discharge was increased to slow the rate of reservoir refill. The Duncan reservoir reached full pool elevation of 1892.0 feet on August 12, 1998.

Duncan essentially passed inflow for the remainder of August to maintain the reservoir near full pool. On September 1, the Duncan discharge was increased to start drafting the reservoir and fill Kootenay Lake to the IJC limit.

Libby Reservoir

As shown in Chart 9, Lake Koocanusa started the operating year at Elevation 2453.56 feet, 5.44 feet down from full. The first 13 days of August Libby released 10,000 cfs and continued to fill. By August 12, Lake Koocanusa reached its maximum summer elevation of 2454.82 feet, 4.18 feet from full. By August 13, the U.S. salmon managers were expected to request the Libby outflow be increased to its full Powerhouse capacity outflow of 24,500 cfs for the remainder of August, which would ultimately draft Lake Koocanusa to an elevation near 2439.0 feet by August 31. Rather than evacuating to an elevation 20 feet from full, the Libby/Arrow storage agreement was initiated by the Canadian Entity on August 13. The Libby outflow was increased to 14,500 cfs, 10,000 cfs less than full Powerhouse capacity. The additional 10,000 cfs was released from Arrow Lakes for the remaining nineteen days of August, hence the total exchange amount of 190 kcfs. Because of the 190 ksfd exchange, Lake Koocanusa ended the month of August at elevation 2450.12 feet, 8.88 feet from full.

September through December 1997 Libby was used for weekly load shaping. The monthly average outflow increased slightly each month. Two periods of minimum outflow were supplied to complete a study of burbot movement downstream of Libby. Those two study periods were November 28 through November 30, 1997, and December 25 through December 28, 1997, when the

Libby outflow was held at 4,000 cfs. In December the monthly average outflow was 22,900 cfs. Lake Koocanusa ended December at elevation 2411.71 feet, within one foot of the normal December 31 flood control point of elevation 2411 feet.

The water supply forecasts at Libby in January through May generally decreased with time. In January the April through August forecast was 5.54 Maf, or 87% of average. In February, March, April, and May the forecasts were 89%, 79%, 82%, and 79% of average, respectively. The end of month flood control target elevations at the end of each month were: January, elevation 2402.7 feet; February, elevation 2392.3 feet; March, 2413.2 feet; and April, 2413.2 feet. In order to achieve these objectives as they varied with each month, the Libby outflow was 8,390 cfs in January and the end of month elevation was 2403.04 feet, or within .34 feet. The February average outflow was 9,420 cfs, and the end of month elevation was 2392.71 feet, or within 0.41 feet of the flood control target. The March water supply forecast diminished by 10% and the end of month flood control elevation went up 20.90 feet. Libby remained on minimum outflow for most of the month of March and drafted slightly to elevation 2391.58 feet. April inflow remained low until the last week. The month average inflow was only 7,980 cfs, while the outflow remained at minimum flow of 4,000 cfs. Lake Koocanusa filled slightly to elevation 2399.62 feet on April 30, still far below the recommended flood control evacuation draft.

Since the May final water supply forecast was less than 80% of average, the U.S. Fish and Wildlife Service agreed to request only one sturgeon pulsing operation. The outflow from Libby remained at minimum of 4,000 cfs through May 11. By May 19, the outflow was 21,600 cfs at Libby. This pulse was delivered wnen the water temperature at Bonners Ferry reached 10° Celsius. After the pulse operation, outflow was ramped down slowly. During the May 28 through June 1 period a rain event in the Kootenai Basin caused Libby outflow to be reduced to as low as 8,500 cfs for downstream flood control. During the month of May, Lake Koocanusa refilled to elevation 2440.15 feet.

The precipitation during the month of May was 201% of average. Because of this wet month, the water supply forecast suddenly increased to 93% of average, but most of the water had already runoff during May. For the month of June, the operational objective was to gradually fill Lake Koocanusa without causing flooding downstream, or threatening to fill and force spill later in the year. During the first 25 days of June the U.S. Fish and Wildlife Service requested steady outflow from the Libby project to maintain a level wetted perimeter after sturgeon spawning occurred during the late May rain event. The outflow from Libby was held near 20,000 cfs through June 25. Inflow in June was 29,740 cfs and outflow was 19,330 cfs. The project filled to elevation 2454.16 feet, only 4.84 feet from full.

During July the objective was to try to maintain a level outflow from Libby that would be maintained through the months of July and August that would evacuate Libby to elevation 2439.0 feet by August 31. This objective was to maintain downstream fishery habitat and supply summer salmon flow while evacuating the project to elevation 2439 feet by August 31. The outflow suggested was to be between 15,000 cfs and 18,000 cfs. While this planning was underway, the Libby/Arrow storage exchange agreement was being negotiated. The storage exchange agreement changed the Libby end of August target elevation and the level outflow required to achieve the elevation. On July 14, the outflow from Libby was reduced to 4,000 cfs for two days to assist a local sheriff's office in search and recovery of two drowning victims near Kootenai Falls. This outflow reduction operation was closely coordinated with three field offices of the U.S. Fish and Wildlife Service and the Montana Fish Wildlife and Parks. Because of the reduced outflow Lake Koocanusa filled to its highest elevation in 1998 on July 16 of 2458.33 feet, only 0.67 feet from full. After the search operation, the project outflow was set at 14,000 cfs again to continue the level flow operation through August; however the Libby /Arrow storage exchange was appearing more likely. Outflow from Libby was reduced to 12,000 cfs by July 23 to prepare for an exchange of as much as 200 ksfd so that the end of August target elevation for Lake Koocanusa was near elevation 2448 feet.

By August 4 the hydrologic conditions in Canada were changing and the amount of storage exchange from Arrow to Libby could not be as high as 200 ksfd. Since Arrow was considered by the Canadian Entity to be drafting too quickly, the Arrow/Libby storage exchange target was reduced. It appeared that only 70 ksfd of storage could be exchanged. In response the Libby project outflow was increased to 22,000 cfs in order to achieve an end of August target elevation below 2448 feet. By August 23 the U.S. and Canada agreed to exchange 106 ksfd of storage in Libby so that the end of August target elevation would be near elevation 2444 feet. The U.S. salmon mangers had a request to have all the water released from Libby prior to the end of August so that it would have traveled past the McNary dam before August 31. To respond to this request the outflow from Libby was ramped down slowly over a six day period from 22,000 cfs to 9,900 cfs on August 28.

Outflow from Libby was increased to 14,900 cfs September 2 through September 5 to meet power demands. After the power need the outflow was 9,000 cfs for a few days and finally 8,000 cfs from the remainder of September 1998. Lake Koocanusa was at elevation 2437.9 feet on September 30, 21.28 feet from full.

Kootenay Lake

As shown in Chart 10, the level of Kootenay Lake at Queens Bay was at elevation 1745.5 feet on July 31, 1997. The lake was gradually drafted during August to meet the summer IJC maximum elevation of 1743.32 feet (Nelson gauge level) and on August 27, was at elevation 1743.1 feet. Discharges were adjusted to pass the inflow until month end.

For the month of September, the Kootenay Lake discharge was adjusted to keep the downstream Brilliant plant at full load without spill at approximately 19 kcfs. The lake level was raised in September, as allowed in the IJC Order, and reached an elevation near 1745 feet by end of October. During October and November, the lake level was kept high by passing inflow, with year-end elevation of 1744.6 feet on December 31, 1997. The lake did not reach the maximum IJC elevation of 1745.32 feet through to January 7, 1998, but remained within 0.5 feet of the IJC level.

Beginning in January, Kootenay Lake was drafted as required by the IJC order. The lake discharges were kept slightly above the inflows during January to mid-March to stay below the IJC limits. The lake reached a minimum level of 1738.6 feet on April 21, 1998, rising quickly thereafter with the commencement of the spring freshet. The inflows peaked on May 27 at 79.8 kcfs. The Kootenay Lake discharges were then also increased, and the outflows from Duncan were reduced to minimum, to reduce the lake level rise in the summer of 1998. The Kootenay Lake discharges peaked on June 6 at 60 kcfs.

Kootenay Lake reached its peak level for the year at elevation 1749.1 feet on June 2, 1998. The lake level gradually started to recede due to receding runoff in June and July, and reduced Libby discharges in July 1998. Kootenay Lake drafted in these months with the lowest summer lake elevation of 1743.0 feet occurring on August 31. Heavy power demand to mid-August also required greater Kootenay Lake discharges and contributed to the lowest month-end elevation. The Nelson gauge level dropped below the IJC summer level elevation of 1743.32 feet on July 27, 1998. Except for one day on August 2, when the elevation reached 1743.38 feet due to unexpected high inflows, lake discharges were adjusted to keep the Nelson gauge level below elevation 1743.32 feet until the end of August. During September, increased outflows from Libby and Duncan, combined with moderate market demand, the lake started to refill gradually. The lake level was controlled in September to maintain operating space to accommodate unit outages at Kootenay projects in the fall as well as potentially high inflows forecast for this winter. The lake is projected to remain near elevation 1744.0 feet in September and mid-October 1998.

Storage Transfer Agreements

In the 1998-99 operating year, the Canadian and U.S. Entities entered into a storage transfer agreement for the summer of 1998 in which increased releases from Canadian Treaty projects were used to reduce the outflow from Libby. This operation resulted in about 107 ksfd less water being released from Libby during August, and reduced the amount of spill at Canadian powerplants on the Kootenay River, while maintaining higher Lake Koocanusa levels in Canada and the U.S. The additional water taken out of Columbia River Treaty Storage will be returned between October 1998 and January 16, 1999.

VI Power and Flood Control Accomplishments

General

During the period covered by this report, Duncan, Arrow, and Mica reservoirs were operated for power, flood control, and other benefits in accordance with the Columbia River Treaty and operating plans and agreements described in Section III. Consistent with all DOP's prepared since the installation of generation at Mica, the 1997-98 and 1998-99 DOP's were designed to achieve optimum power generation at-site in Canada and downstream in Canada and the United States, in accordance with paragraph 7 of Annex A of the Treaty.

During the period covered by this report, Libby reservoir was operated for flood control and other purposes in accordance with the Treaty and the 1972 "Columbia River Treaty Flood Control Operating Plan," as amended by the U.S. Army Corps of Engineers (ACE) "Review of Flood Control, Columbia River Basin, Columbia River & Tributaries Study, CRT-63", dated June 1981. During a portion of the year, Libby operated for power purposes according to the Pacific Northwest Coordination Agreement (PNCA) Actual Energy Regulation (AER). During the remainder of the operating year, Libby operated for storage and releases recommended for endangered White Sturgeon and Salmon by both the U.S. Fish and Wildlife Service and the National Marine Fishery Service Biological Opinions. As recorded in the Detailed Operating Plan for the current year, the Entities could not agree on operations of Libby project.

Flood Control

The Columbia River Basin reservoir system, including the Columbia River Treaty projects, was operated on a daily basis for flood control for only a short time in the spring of 1998 as heavy rains caused a sharp rise in runoff in late May. The observed and unregulated hydrographs for the Columbia River at The Dalles between April 1, 1998, and July 31, 1998, are shown on Chart 14. The unregulated peak flow at The Dalles would have been 617,000 cfs on May 29, 1998, and it was controlled to a maximum of 442,200 cfs on May 30, 1998. The observed peak stage at Vancouver, Washington was 14.8 feet on June 1, 1998, and the unregulated stage would have been 22.4 feet on May 31, 1998.

Chart 15 documents the relative filling of Arrow and Grand Coulee during the principal filling period, and compares the regulation of these two reservoirs to guidelines in the Treaty Flood Control Operating Plan. Because this year's runoff volume was low and Arrow was drafted deeply for power, there was no daily flood control operation at Arrow after April 30, 1998.

Computations of the Initial Controlled Flow (ICF) for system flood control operation were made in accordance with the Treaty Flood Control Operating Plan. Computed Initial Controlled Flows at The Dalles were 278,000 cfs on January 1, 1998, 308,000 cfs on February 1, 297,000 cfs on March 1, 287,000 cfs on April 1, and 254,000 cfs on May 1. As mentioned earlier, the observed peak flow at The Dalles was 442,200 cfs. Data for the May 1, ICF computation is given in Table 6.

Canadian Entitlement

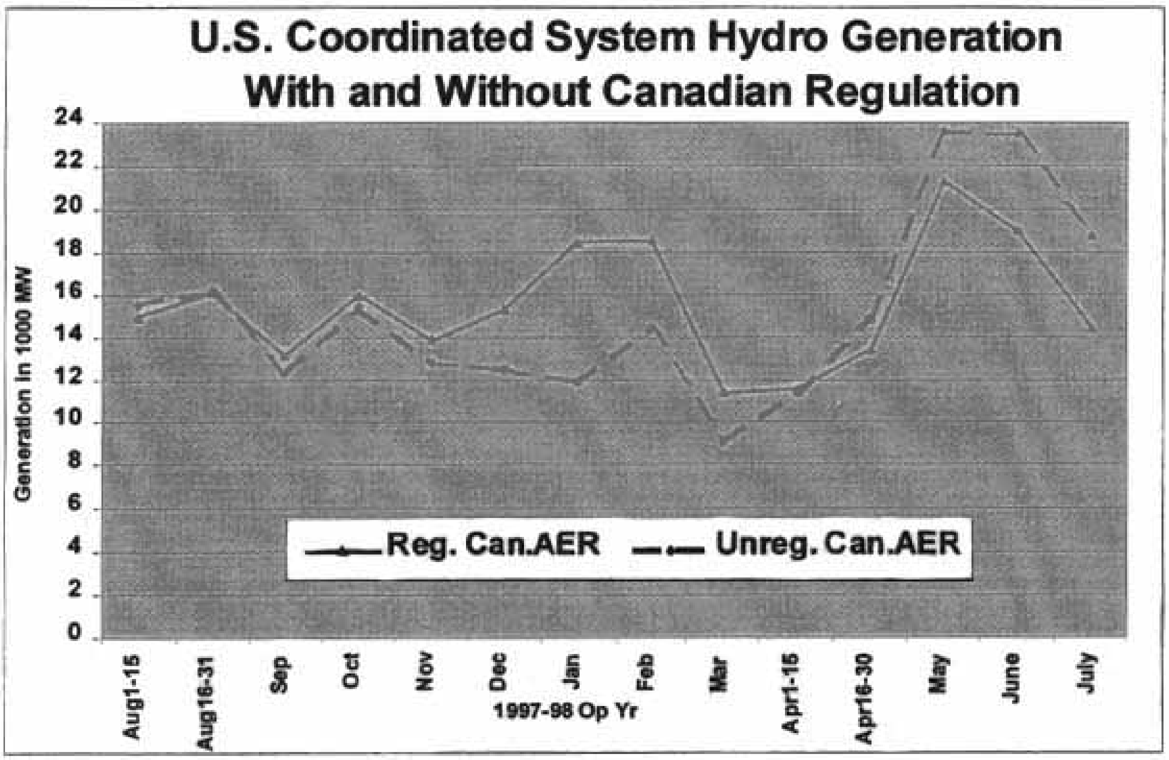
The Canadian Entitlement to downstream power benefits from Duncan, Arrow, and Mica for most of 1997-98 operating year had been purchased in 1964 by the Columbia Storage Power Exchange (CSPE). The sale of the Canadian Entitlement to downstream power benefits from the operation of Duncan reservoir terminated on March 31, 1998, 2400 hours. In accordance with the Canadian Entitlement Exchange Agreement dated August 13, 1964, the U.S. Entity delivered capacity and energy to the CSPE participants. The generation at downstream projects in the United States, delivered under the Canadian Entitlement Exchange, was 246 average megawatts from August 1, 1997, through March 31, 1998, and 215 average megawatts from April 1, 1998 through July 31, 1998. Capacity deliveries were up to 471 megawatts from August 1, 1997, through March 31, 1998, and 416 megawatts from April 1, 1998, through July 31, 1998.

In accordance with the Entity Agreement on the Determination of Downstream Power Benefits for Operating Year 1997-98, the Canadian Entity delivered to the U.S. Entity 2.8 average megawatts of annual energy and no dependable capacity during the period August 1, 1997, through March 31, 1998. In accordance with the Entity Agreement on the Determination of Downstream Power Benefits for Operating Year 1998-99, the Canadian Entity delivered to the U.S. Entity 3.7 average megawatts of annual energy and 0.4 megawatts dependable capacity during the period April 1, 1998, through July 31, 1998. These energy deliveries were required by Section 7 of the August 1964 Canadian Entitlement Purchase Agreement.

On April 1, 1998, the first return of Canadian Entitlement power to British Columbia since 1968 began flowing at the existing points of interconnections between BPA and B.C. Hydro. These deliveries were for the Canadian Entitlement to downstream power benefits from the operation of Duncan reservoir. The initial amount delivered, not including transmission losses and scheduling adjustments, was 50.0 average MW at rates up to 111.1 MW. On August 1, 1998, the Canadian Entitlement returned increased to 50.8 average MW at rates up to 136.8 MW.

Power Generation and Other Accomplishments

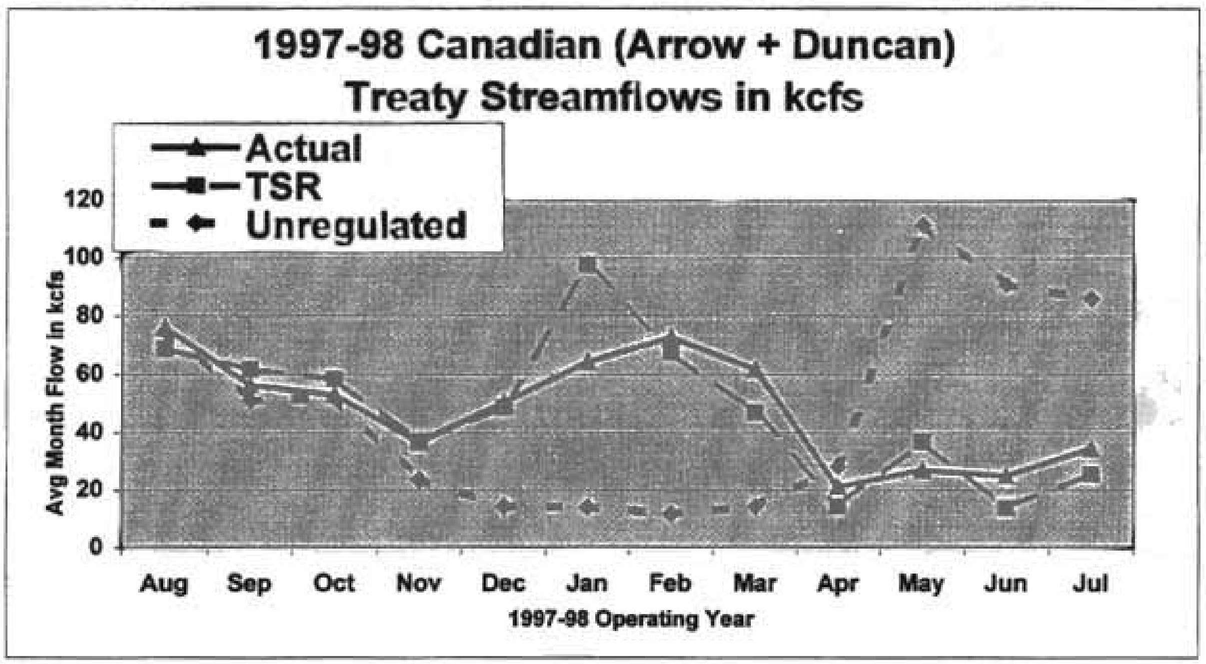
The Coordinated System storage level at the beginning of the 1997-98 operating year was 99.09 percent full as of 31 July 1997 as measured in the Pacific Coordination Agreement (PNCA) Actual Energy Regulation (AER). The Treaty Storage operation outlined in the AER is fixed from the Treaty Storage Regulation (TSR) study. Since the System was 99.09 percent full, 1st-year firm energy load carrying capability (FELCC) was adopted for the U.S. system from the PNCA critical period studies. Due to above average streamflows throughout the year, the system generally operated to Operating Rule Curve (ORC) or flood control for the entire period, producing large amounts of surplus energy. The system storage energy reached 99.39 percent full on 31 July 1998, as measured in the AER, and the system adopted 1st-year FELCC from the 1998-99 PNCA Final Regulation study.



Actual U.S. power benefits from the operation of Treaty storage are unknown due to the complicated nature of hourly power operations and the need to speculate on alternative operating procedures, nonpower requirements, and market conditions in the absence of Treaty storage. However, the graph on this page shows a rough estimate of the average monthly impact on downstream U.S. power generation during the 1997-98 operating year, with and without the regulation of Canadian Treaty storage, based on the PNCA AER that includes minimum flow and spill constraints for U.S. fishery objectives. The U.S. gain in average annual usable energy, computed as firm energy, plus non-firm energy that displaces PNCA thermal resources, plus 40% of the remaining nonfirm energy, was 1022 aMW.

Based on the authority from the 1997-98 and 1998-99 DOP's, the Operating Committee completed several operating agreements, described in Section III, that resulted in power and other benefits both in Canada and the U.S. Other benefits include increased reservoir levels for summer recreation and dust storm avoidance and changes to streamflows below Arrow that enhanced trout and whitefish spawning and the downstream migration of salmon. The following graph shows the difference at the U.S. border between average monthly regulated DOP TSR stream flows and the actual stream flows due to these agreements. The unregulated stream flows are also shown for comparison purposes.

As of September 30, 1997, the sum of Canadian Treaty storage was positioned 95 ksfd below the DOP TSR. The Entities drafted a total of 190 ksfd below the TSR by August 31, 1997, per the terms of the Arrow/Libby Swap Agreement, with the U.S. returning their half of the Swap by the end of September.



In early October, the U.S. and BCH agreed to store water into Treaty space to avoid spill at Grand Coulee Dam, per the Columbia River Treaty Operating Committee Agreement on the Operation of Treaty Storage For Fall Provisional Storage and Mountain Whitefish Spawning Flows through March 31, 1998. Water stored under this agreement was to be released during February and March for the benefit of both power and whitefish. Two hundred ksfd were stored consistent with the terms of this agreement.

Beginning January 1998, Arrow's discharge was again reduced below TSR levels per the terms of the Columbia River Treaty Operating Committee Agreement on the Operation of Treaty Storage for the Enhancement of Mountain Whitefish Spawning for September 20, 1997, through April 30, 1998. By the end of whitefish spawning the whole of Canadian storage was approximately 1100 ksfd above TSR. This water was released throughout February and March consistent with the above agreements, such that by the end of March about 500 ksfd (approximately 1 maf) was left in Canadian storage. This amount was consistent with the U.S. need for flow augmentation as allowed for in the Columbia River Treaty Agreement On Operation of Treaty Storage for Non-Power Uses for January 1, 1997, through July 31, 1997.

During the April through July 1998 period, water was stored and released in a manner consistent with Canada's need for trout spawning and progressive Arrow refill and the U.S. need for salmon flow augmentation and flood control. By July 1998, Canadian storage was returned to its TSR elevation.

Table 1

Unregulated Runoff Volume Forecasts
Million of Acre-Feet
1998

Forecast Date - 1st of	Duncan Most Probable 1 April - 31 August	Arrow Most Probable 1 April - 31 August	Mica Most Probable 1 April - 31 August	Libby Most Probable 1 April - 31 August	Columbia River at The Dalles, Oregon Most Probable 1 April - 31 August
January	1.9	21.5	10.7	5.5	76.1
February	2.0	22.2	10.6	5.6	83.3
March	1.9	21.3	10.0	5.1	79.5
April	2.0	21.2	10.4	5.2	77.2
May	1.9	19.5	10.1	5.1	75.4
June	1.9	20.4	10.1	5.9	88.6
Actual	2.0	20.8	11.0	5.8	90.1

NOTE: These data were used in actual operations. Subsequent revisions have been made in some cases.

TABLE 2
1998 Variable Refill Curve
Mica Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW,KAF			8890.0	8771.0	8074.8	7916.1	7368.7	4685.0
PROBABLE DATE-31JULY INFLOW,KSFD	**		4482.0	4422.0	4071.0	3991.0	3715.0	2362.0
95% FORECAST ERROR FOR DATE, KSFD			653.0	510.4	465.4	444.5	360.5	360.5
95% CONF.DATE-31JULY INFLOW,KSFD	1/		3829.0	3911.6	3605.6	3546.5	3354.5	2001.5
ASSUMED FEB1-JUL31 INFLOW,% OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW,KSFD	2/		4084.7					
FEB MINIMUM FLOW REQUIREMENT,CFS	3/		3000.0					
MIN FEB1-JUL31 OUTFLOW,KSFD	4/		3367.0					
MIN JAN31 RESERVOIR CONTENT,KSFD	5/		3067.2					
MIN JAN31 RESERVOIR CONTENT,FEET	6/		2461.2					
JAN31 ECC,FT.	7/		2451.7					
BASE ECC, FT		2451.7						
LOWER LIMIT,FT		2411.0						
ASSUMED MAR1-JUL31 INFLOW,% OF VOL.			97.6	97.6				
ASSUMED MAR1-JUL31 INFLOW,KSFD	2/		3737.1	3817.7				
MAR MINIMUM FLOW REQUIREMENT,CFS	3/		3000.0	3000.0				
MIN MAR1-JUL31 OUTFLOW,KSFD	4/		3050.1	1811.7				
MIN FEB28 RESERVOIR CONTENT,KSFD	5/		2842.2	1523.3				
MIN FEB28 RESERVOIR CONTENT,FEET	6/		2456.7	2429.5				
FEB28 ECC,FT.	7/		2441.7	2429.5				
BASE ECC,FT		2441.7						
LOWER LIMIT,FT		2398.8						
ASSUMED APR1-JUL31 INFLOW,% OF VOL.			95.1	95.1	97.4			
ASSUMED APR1-JUL31 INFLOW,KSFD	2/		3641.4	3719.9	3511.9			
APR MINIMUM FLOW REQUIREMENT,CFS	3/		3000.0	3000.0	3000.0			
MIN APR1-JUL31 OUTFLOW,KSFD	4/		2699.1	1718.7	1949.8			
MIN MAR31 RESERVOIR CONTENT,KSFD	5/		2587.0	1528.0	1967.1			
MIN MAR31 RESERVOIR CONTENT,FEET	6/		2451.7	2429.6	2439.0			
MAR31 ECC,FT.	7/		2430.7	2429.6	2430.7			
BASE ECC,FT		2430.7						
ASSUMED MAY1-JUL31 INFLOW,% OF VOL.			90.0	90.0	92.2	94.7		
ASSUMED MAY1-JUL31 INFLOW,KSFD	2/		3446.1	3520.4	3324.4	3358.5		
MAY MINIMUM FLOW REQUIREMENT,CFS	3/		3000.0	3000.0	3000.0	3000.0		
MIN MAY1-JUL31 OUTFLOW,KSFD	4/		2275.3	1524.3	1702.0	1831.0		
MIN APR30 RESERVOIR CONTENT,KSFD	5/		2358.5	1533.1	1906.8	2001.7		
MIN APR30 RESERVOIR CONTENT,FEET	6/		2447.1	2429.7	2437.7	2439.7		
APR30 ECC,FT.	7/		2420.8	2420.8	2420.8	2420.8		
BASE ECC,FT		2420.8						
ASSUMED JUN1-JUL31 INFLOW,% OF VOL.			71.6	71.6	73.3	75.3	79.5	
ASSUMED JUN1-JUL31 INFLOW,KSFD	2/		2741.5	2800.7	2642.9	2670.5	2666.8	
JUN MINIMUM FLOW REQUIREMENT,CFS	3/		10000.0	10000.0	10000.0	10000.0	10000.0	
MIN JUN1-JUL31 OUTFLOW,KSFD	4/		1535.5	1216.3	1292.8	1347.4	1347.4	
MIN MAY31 RESERVOIR CONTENT,KSFD	5/		2323.1	1944.9	2179.1	2206.1	2209.8	
MIN MAY31 RESERVOIR CONTENT,FEET	6/		2446.4	2438.5	2443.4	2444.0	2444.1	
MAY31 ECC,FT.	7/		2425.0	2425.0	2425.0	2425.0	2425.0	
BASE ECC,FT		2425.0						
ASSUMED JUL1-JUL31 INFLOW,% OF VOL.			35.5	35.5	36.3	37.3	39.4	0.5
ASSUMED JUL1-JUL31 INFLOW,KSFD	2/		1359.3	1388.6	1308.8	1322.8	1321.7	990.8
JUL MINIMUM FLOW REQUIREMENT,CFS	3/		10000.0	10000.0	10000.0	10000.0	10000.0	10000.0
MIN JUL1-JUL31 OUTFLOW,KSFD	4/		727.5	618.1	644.8	663.4	663.4	601.4
MIN JUN30 RESERVOIR CONTENT,KSFD	5/		2897.4	2758.7	2865.2	2869.8	2870.9	3139.8
MIN JUN30 RESERVOIR CONTENT,FEET	6/		2457.9	2455.2	2457.2	2457.3	2457.4	2462.6
JUN30 ECC,FT.	7/		2449.2	2449.2	2449.2	2449.2	2449.2	2449.2
BASE ECC,FT		2449.2						
JUL 31 ECC, FT			2470.1	2470.1	2470.1	2470.1	2470.1	2470.1

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINU.S. (95% ERROR & JAN1-DATE INFLOW). 2/PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS. 4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
5/ FULL CONTENT (3529.2 KSFD) PLU.S. 4/ MINU.S. /2. 6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE.A143
7/ LOWER OF ELEVATION FROM 6/ OR BASE ECC DETERMINED PRIOR TO YEAR (INTIAL), BUT NOT LESS THAN LOWER LIMIT.

TABLE 3
1998 Variable Refill Curve
Arrow Reservoir

		INITIAL	JAN 1 Local	FEB 1 Local	MAR 1 Local	APR 1 Local	MAY 1 Local	JUN 1 Local
PROBABLE DATE-31JULY INFLOW, KAF			9887.7	10685.1	10094.0	8120.4	7142.5	4322.0
& IN KSFD	**		4985.0	5387.0	5089.0	4094.0	3601.0	2179.0
95% FORECAST ERROR FOR DATE, IN KSFD			762.0	632.8	505.1	403.5	341.6	341.6
95% CONF.DATE-31JULY INFLOW, KSFD	1/		4223.0	4754.2	4583.9	3690.5	3259.4	1837.4
ASSUMED FEB1-JUL31 INFLOW,% OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW, KSFD	2/		4223.0					
MIN FEB1-JUL31 OUTFLOW, KSFD	3/		3381.4					
UPSTREAM REFILL, KSFD	4/		3161.6					
MIN FEB28 RESERVOIR CONTENT, KSFD	5/		0.0					
MIN JAN31 RESERVOIR CONTENT, FEET	6/		1377.9					
JAN31 ECC, FT.	7/		1403.4					
BASE ECC, FT		1411.4						
LOWER LIMIT, FT		1403.4						
ASSUMED MAR1-JUL31 INFLOW,% OF VOL.			97.3	97.3				
ASSUMED MAR1-JUL31 INFLOW, KSFD	2/		4109.0	4625.8				
MIN MAR1-JUL31 OUTFLOW, KSFD	3/		3144.3	2300.2				
UPSTREAM REFILL, KSFD	4/		2545.6	2591.5				
MIN FEB28 RESERVOIR CONTENT, KSFD	5/		69.3	0.0				
MIN FEB28 RESERVOIR CONTENT, FEET	6/		1379.6	1377.9				
FEB28 ECC, FT.	7/		1385.2	1385.2				
BASE ECC, FT		1392.7						
LOWER LIMIT, FT		1385.2						
ASSUMED APR1-JUL31 INFLOW,% OF VOL.			93.9	93.9	96.4			
ASSUMED APR1-JUL31 INFLOW, KSFD	2/		3965.4	4461.1	4418.9			
MIN APR1-JUL31 OUTFLOW, KSFD	3/		2881.9	2145.2	2311.2			
UPSTREAM REFILL, KSFD	4/		1739.6	1785.5	1714.5			
MIN MAR31 RESERVOIR CONTENT, KSFD	5/		756.4	0.0	0.0			
MIN MAR31 RESERVOIR CONTENT, FEET	6/		1394.8	1377.9	1377.9			
MAR31 ECC, FT.	7/		1394.8	1377.9	1377.9			
BASE ECC, FT		1403.5						
ASSUMED MAY1-JUL31 INFLOW,% OF VOL.			85.3	85.3	87.6	90.9		
ASSUMED MAY1-JUL31 INFLOW, KSFD	2/		3602.2	4055.3	4015.5	3354.7		
MIN MAY1-JUL31 OUTFLOW, KSFD	3/		2523.9	1995.2	2113.2	2205.6		
UPSTREAM REFILL, KSFD	4/		920.0	920.0	920.0	920.0		
MIN APR30 RESERVOIR CONTENT, KSFD	5/		1581.2	599.5	757.3	1510.5		
MIN APR30 RESERVOIR CONTENT, FEET	6/		1410.7	1391.6	1394.8	1409.4		
APR30 ECC, FT.	7/		1406.8	1391.6	1394.8	1399.9		
BASE ECC, FT		1406.8						
ASSUMED JUN1-JUL31 INFLOW,% OF VOL.			59.9	59.9	61.5	63.8	70.2	
ASSUMED JUN1-JUL31 INFLOW, KSFD	2/		2529.6	2847.7	2819.1	2354.5	2281.1	
MIN JUN1-JUL31 OUTFLOW, KSFD	3/		1736.5	1533.1	1573.8	1610.4	1610.4	
UPSTREAM REFILL, KSFD	4/		610.0	610.0	610.0	610.0	610.0	
MIN MAY31 RESERVOIR CONTENT, KSFD	5/		2176.5	1655.0	1724.3	2225.5	2291.9	
MIN MAY31 RESERVOIR CONTENT, FEET	6/		1419.4	1412.1	1413.4	1422.0	1421.3	
MAY31 ECC, FT.	7/		1419.1	1412.1	1413.4	1419.1	1419.1	
BASE ECC, FT		1419.1						
ASSUMED JUL1-JUL31 INFLOW,% OF VOL.			25.6	25.6	26.3	27.3	30.0	42.7
ASSUMED JUL1-JUL31 INFLOW, KSFD	2/		1081.1	1217.1	1205.8	1007.5	977.8	784.6
MIN JUL1-JUL31 OUTFLOW, KSFD	3/		882.5	779.1	799.8	818.4	818.4	816.3
UPSTREAM REFILL, KSFD	4/		310.0	310.0	310.0	310.0	310.0	310.0
MIN JUN30 RESERVOIR CONTENT, KSFD	5/		3071.1	2831.7	2863.8	3080.5	3110.2	3301.4
MIN JUN30 RESERVOIR CONTENT, FEET	6/		1436.1	1432.3	1432.8	1436.3	1436.7	1439.7
JUN30 ECC, FT.	7/		1436.1	1432.3	1432.8	1436.3	1436.7	1437.2
BASE ECC, FT		1437.2						
JUL 31 ECC, FT			1444.0	1444.0	1444.0	1444.0	1444.0	1444.0

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINU.S. (95% ERROR & JAN1-DATE INFLOW). 2/PRECEEDING LINE TIMES 1/.
3/ CUMMULATIVE MINIMUM OUTFLOW FROM DATE TO JULY, USING POWER DISCHARGE REQUIREMENTS
4/ UPSTREAM DISCHARGE REQUIREMENT. 5/ FULL CONTENT(3579.6 KSFD) MINU.S. 2/ PLU.S. 3/ PLU.S. /4.
6/ ELEVATION FROM 5/, INTERP. FROM STORAGE CONTENT TABLE
7/ LOWER OF ELEVATION FROM 6/ OR ELEV DETERMINED PRIOR TO YEAR (INTIAL), BUT NOT LESS THAN LOWER LIMIT.

TABLE 4
1998 Variable Refill Curve
Duncan Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW,KAF			1628.4	1753.4	1638.3	1527.3	1398.3	841.0
& IN KSFD	**		821.0	884.0	826.0	770.0	705.0	424.0
95% FORECAST ERROR FOR DATE,IN KSFD			118.4	108.9	97.5	88.1	73.3	73.3
95% CONF.DATE-31JULY INFLOW,KSFD	1/		702.6	775.1	728.5	681.9	631.7	350.7
ASSUMED FEB1-JUL31 INFLOW,% OF VOL.			100.0					
ASSUMED FEB1-JUL31 INFLOW,KSFD	2/		702.8					
FEB MINIMUM FLOW REQUIREMENT,CFS	3/		100.0					
MIN FEB1-JUL31 OUTFLOW,KSFD	4/		205.2					
MIN JAN31 RESERVOIR CONTENT,KSFD	5/		208.5					
MIN JAN31 RESERVOIR CONTENT,FEET	6/		1830.2					
JAN31 ECC,FT	7/		1830.2					
BASE ECC,FT		1842.5						
ASSUMED MAR1-JUL31 INFLOW,% OF VOL.			97.8	97.8				
ASSUMED MAR1-JUL31 INFLOW,KSFD	2/		687.2	758.0				
MAR MINIMUM FLOW REQUIREMENT,CFS	3/		100.0	100.0				
MIN MAR1-JUL31 OUTFLOW,KSFD	4/		185.0	15.3				
MIN FEB28 RESERVOIR CONTENT,KSFD	5/		203.6	0.0				
MIN FEB28 RESERVOIR CONTENT,FEET	6/		1829.5	1794.2				
FEB28 ECC,FT.	7/		1817.1	1794.2				
BASE ECC,FT		1831.5						
ASSUMED APR1-JUL31 INFLOW,% OF VOL.			95.3	95.3	97.4			
ASSUMED APR1-JUL31 INFLOW,KSFD	2/		669.6	738.6	709.5			
APR MINIMUM FLOW REQUIREMENT,CFS	3/		100.0	100.0	100.0			
MIN APR1-JUL31 OUTFLOW,KSFD	4/		162.5	12.2	46.9			
MIN MAR31 RESERVOIR CONTENT,KSFD	5/		198.7	0.0	43.1			
MIN MAR31 RESERVOIR CONTENT,FEET	6/		1828.8	1794.2	1803.6			
MAR31 ECC,FT.	7/		1817.1	1794.2	1803.6			
BASE ECC,FT		1832.1						
ASSUMED MAY1-JUL31 INFLOW,% OF VOL.			89.2	89.2	91.1	93.5		
ASSUMED MAY1-JUL31 INFLOW,KSFD	2/		626.8	691.3	663.6	637.6		
MAY MINIMUM FLOW REQUIREMENT,CFS	3/		100.0	100.0	100.0	100.0		
MIN MAY1-JUL31 OUTFLOW,KSFD	4/		130.4	9.2	37.2	58.1		
MIN APR30 RESERVOIR CONTENT,KSFD	5/		209.4	23.7	79.3	126.4		
MIN APR30 RESERVOIR CONTENT,FEET	6/		1830.3	1799.7	1810.1	1817.8		
APR30 ECC,FT.	7/		1817.1	1799.7	1810.2	1811.3		
BASE ECC,FT		1833.3						
ASSUMED JUN1-JUL31 INFLOW,% OF VOL.			67.6	67.6	69.1	70.9	75.8	
ASSUMED JUN1-JUL31 INFLOW,KSFD	2/		475.0	523.9	503.4	483.5	478.8	
JUN MINIMUM FLOW REQUIREMENT,CFS	3/		100.0	100.0	100.0	100.0	100.0	
MIN JUN1-JUL31 OUTFLOW,KSFD	4/		86.5	6.1	24.6	38.6	38.6	
MIN MAY31 RESERVOIR CONTENT,KSFD	5/		317.3	188.0	227.1	260.9	265.5	
MIN MAY31 RESERVOIR CONTENT,FEET	6/		1845.2	1827.3	1832.9	1837.6	1838.2	
MAY31 ECC,FT.	7/		1845.2	1827.3	1832.9	1837.6	1838.2	
BASE ECC,FT		1848.7						
ASSUMED JUL1-JUL31 INFLOW,% OF VOL.			31.7	31.7	32.4	33.3	35.6	46.9
ASSUMED JUL1-JUL31 INFLOW,KSFD	2/		222.7	245.7	236.0	227.1	224.9	164.5
JUL MINIMUM FLOW REQUIREMENT,CFS	3/		100.0	100.0	100.0	100.0	100.0	100.0
MIN JUL1-JUL31 OUTFLOW,KSFD	4/		43.9	3.1	12.5	19.6	19.6	3.1
MIN JUN30 RESERVOIR CONTENT,KSFD	5/		527.0	463.2	482.3	498.3	500.5	544.4
MIN JUN30 RESERVOIR CONTENT,FEET	6/		1871.3	1863.7	1866.0	1867.9	1868.2	1873.3
JUN30 ECC,FT.	7/		1871.3	1863.7	1866.0	1867.9	1868.2	1873.0
BASE ECC,FT		1873.0						
JUL 31 ECC, FT..................			1892.0	1892.0	1892.0	1892.0	1892.0	1892.0

** FORECAST START DATE IS 1FEB OR LATER. OBSERVED INFLOW FROM 1JAN-DATE IS SUBTRACTED.
1/ PROBABLE INFLOW MINU.S. (95% ERROR & JAN1-DATE INFLOW). 2/PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS. 4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
5/ FULL CONTENT (705.8 KSFD) PLU.S. 4/ MINU.S. /2. 6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE.
7/ LOWER OF ELEVATION FROM 6/ OR BASE ECC DETERMINED PRIOR TO YEAR (INTIAL),BUT NOT LESS THAN LOWER LIMIT.

TABLE 5
1998 Variable Refill Curve
Libby Reservoir

		INITIAL	JAN 1	FEB 1	MAR 1	APR 1	MAY 1	JUN 1
PROBABLE DATE-31JULY INFLOW,KAF			5641.0	5741.0	5208.0	5346.0	5226.0	6255.0
PROBABLE DATE-31JULY INFLOW,KSFD			2844.0	2894.4	2625.7	2695.3	2634.8	3153.6
OBSERVED JAN1-DATE INFLOW, IN KSFD			886.8	606.4	552.5	533.4	474.5	367.5
95% FORECAST ERROR FOR DATE, KSFD			0.0	105.9	202.7	319.1	566.7	1662.2
95% CONF.DATE-31JULY INFLOW,KSFD	1/		1957.2	2182.1	1870.5	1842.7	1593.6	1123.8
ASSUMED FEB1-JUL31 INFLOW,% OF VOL.			97.0					
ASSUMED FEB1-JUL31 INFLOW,KSFD	2/		1897.7					
FEB MINIMUM FLOW REQUIREMENT,CFS	3/		4000.0					
MIN FEB1-JUL31 OUTFLOW,KSFD	4/		1045.2					
MIN JAN31 RESERVOIR CONTENT,KSFD	5/		1658.0					
MIN JAN31 RESERVOIR CONTENT,FEET	6/		2419.3					
JAN31 ECC,FT.	7/		2416.5					
BASE ECC, FT		2416.6						
LOWER LIMIT,FT		2291.3						
ASSUMED MAR1-JUL31 INFLOW,% OF VOL.			94.2	97.1				
ASSUMED MAR1-JUL31 INFLOW,KSFD	2/		1843.3	2119.7				
MAR MINIMUM FLOW REQUIREMENT,CFS	3/		4000.0	4013.3				
MIN MAR1-JUL31 OUTFLOW,KSFD	4/		933.2	848.1				
MIN FEB28 RESERVOIR CONTENT,KSFD	5/		1600.4	1238.9				
MIN FEB28 RESERVOIR CONTENT,FEET	6/		2416.2	2395.5				
FEB28 ECC,FT.	7/		2413.8	2395.5				
BASE ECC,FT		2413.8						
LOWER LIMIT,FT		2287.0						
ASSUMED APR1-JUL31 INFLOW,% OF VOL.			90.8	93.7	96.4			
ASSUMED APR1-JUL31 INFLOW,KSFD	2/		1777.4	2043.8	1803.5			
APR MINIMUM FLOW REQUIREMENT,CFS	3/		5346.7	4013.3	4320.0			
MIN APR1-JUL31 OUTFLOW,KSFD	4/		809.2	723.7	738.9			
MIN MAR31 RESERVOIR CONTENT,KSFD	5/		1542.4	1190.4	1445.9			
MIN MAR31 RESERVOIR CONTENT,FEET	6/		2413.1	2392.4	2407.8			
MAR31 ECC,FT.	7/		2411.0	2392.4	2407.8			
BASE ECC,FT		2410.3						
LOWER LIMIT,FT		2287.0						
ASSUMED MAY1-JUL31 INFLOW,% OF VOL.			82.7	85.3	87.8	91.1		
ASSUMED MAY1-JUL31 INFLOW,KSFD	2/		1618.6	1861.1	1642.3	1678.2		
MAY MINIMUM FLOW REQUIREMENT,CFS	3/		5673.3	5000.0	5160.0	5280.0		
MIN MAY1-JUL31 OUTFLOW,KSFD	4/		643.9	588.5	596.7	607.8		
MIN APR30 RESERVOIR CONTENT,KSFD	5/		1535.8	1237.9	1464.9	1440.1		
MIN APR30 RESERVOIR CONTENT,FEET	6/		2412.8	2395.4	2408.9	2407.5		
APR30 ECC,FT.	7/		2410.1	2395.4	2408.9	2407.5		
BASE ECC,FT		2410.1						
ASSUMED JUN1-JUL31 INFLOW,% OF VOL.			55.3	57.0	58.7	60.9	66.9	
ASSUMED JUN1-JUL31 INFLOW,KSFD	2/		1082.0	1244.3	1098.0	1121.9	1065.3	
JUN MINIMUM FLOW REQUIREMENT,CFS	3/		7673.3	7106.7	7160.0	7280.0	7280.0	
MIN JUN1-JUL31 OUTFLOW,KSFD	4/		468.1	433.5	436.8	444.1	444.1	
MIN MAY31 RESERVOIR CONTENT,KSFD	5/		1896.6	1699.8	1849.3	1832.7	1889.3	
MIN MAY31 RESERVOIR CONTENT,FEET	6/		2431.2	2421.4	2428.9	2428.0	2430.8	
MAY31 ECC,FT.	7/		2430.3	2421.4	2428.9	2428.0	2430.3	
BASE ECC,FT		2430.3						
ASSUMED JUL1-JUL31 INFLOW,% OF VOL.			19.6	20.2	20.8	21.6	23.7	35.5
ASSUMED JUL1-JUL31 INFLOW,KSFD	2/		383.6	441.2	389.3	397.7	377.7	398.4
JUL MINIMUM FLOW REQUIREMENT,CFS	3/		7673.3	7106.7	7160.0	7280.0	7280.0	8066.7
MIN JUL1-JUL31 OUTFLOW,KSFD	4/		237.9	220.3	222.0	225.7	225.7	250.1
MIN JUN30 RESERVOIR CONTENT,KSFD	5/		2364.8	2289.6	2343.2	2338.5	2358.5	2362.2
MIN JUN30 RESERVOIR CONTENT,FEET	6/		2452.7	2449.4	2451.7	2451.5	2452.4	2452.6
JUN30 ECC,FT.	7/		2452.7	2449.4	2451.7	2451.5	2452.4	2452.6
BASE ECC,FT		2459.0						
JUL 31 ECC, FT			2459.0	2459.0	2459.0	2459.0	2459.0	2459.0
JAN1-JUL31 FORECAST,-EARLYBIRD,MAF	8/		84.9	95.2	92.6	90.8	90.8	97.0

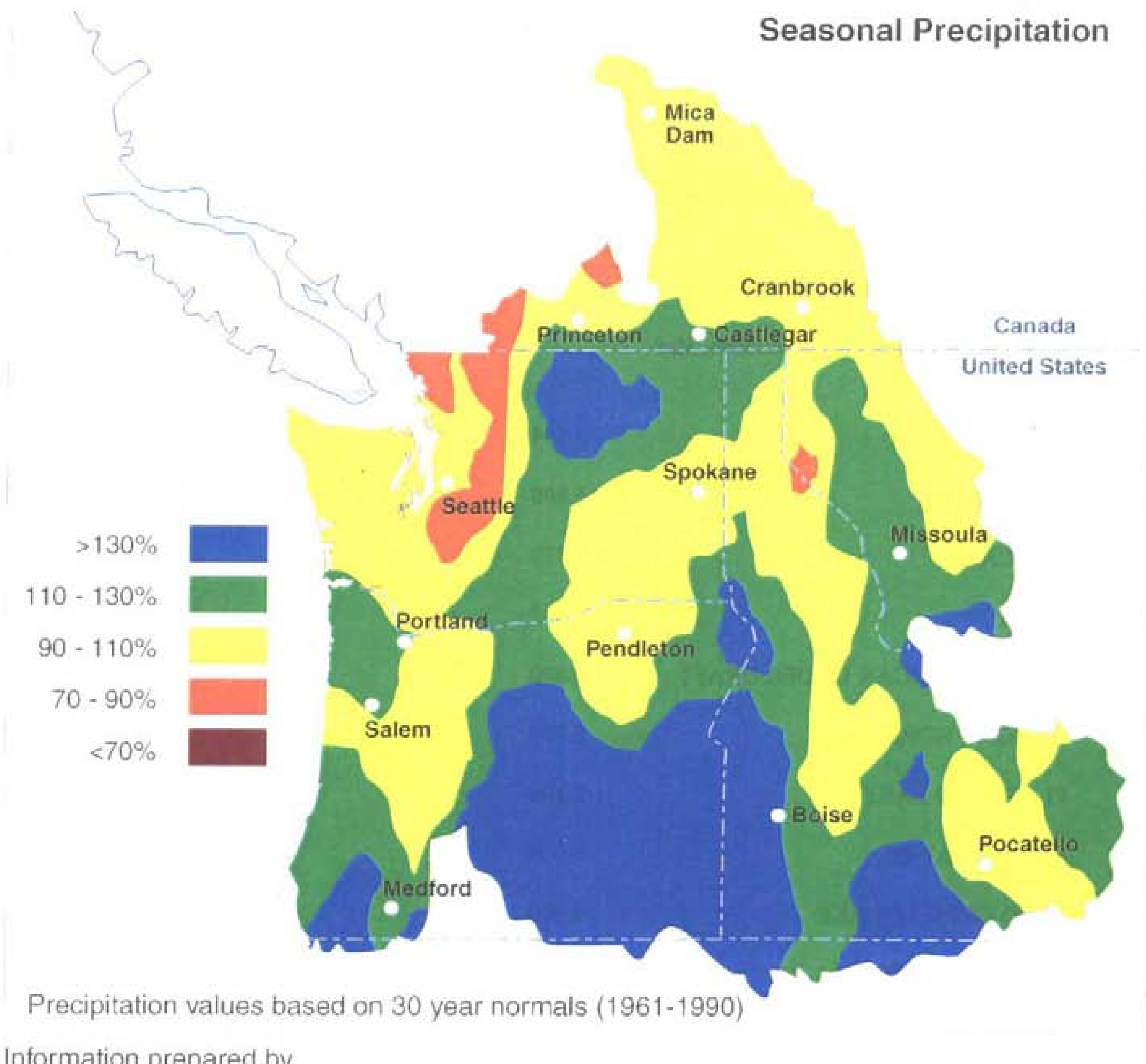
1/ PROBABLE INFLOW MINUS (95% ERROR & JAN1-DATE INFLOW) MINUS OBSERVED INFLOW. 2/PRECEEDING LINE TIMES 1/.
3/ POWER DISCHARGE REQUIREMENTS. 4/ CUMULATIVE MINIMUM OUTFLOW FROM 3/,DATE TO JULY.
5/ FULL CONTENT (2510.5 KSFD) PLUS 4/ MINUS /2. 6/ ELEV FROM 5/, INTERP FROM STORAGE CONTENT TABLE.A143
7/ LOWER OF ELEV. FROM 6/ OR BASE ECC DETERMINED PRIOR TO YEAR (INTIAL),BUT NOT LESS THAN LOWER LIMIT.
8/ USED TO CALCULATE THE POWER DISCHARGE REQUIREMENTS FOR 3/.

Table 6

Computation of Initial Controlled Flow
Columbia River at The Dalles
1 May 1998

1 May Forecast of May-August Unregulated Runoff Volume, Maf		75.4
Less Estimated Depletions, Maf		1.5
Less Upstream Storage Corrections, Maf		18.105
MICA	5.544	
ARROW	5.000	
DUNCAN	1.335	
LIBBY	2.412	
LIBBY + DUNCAN UNDER DRAFT	0.000	
HUNGRY HORSE	0.888	
FLATHEAD LAKE	0.500	
NOXON RAPIDS	0.000	
PEND OREILLE LAKE	0.500	
GRAND COULEE	1.043	
BROWNLEE	0.540	
DWORSHAK	0.649	
JOHN DAY	0.180	
TOTAL	18.105	18.105
Forecast of Adjusted Residual Runoff Volume, Maf		42.195
Computed Initial Controlled Flow from Chart 1 of Flood Control Operating Plan, 1,000 cfs		254

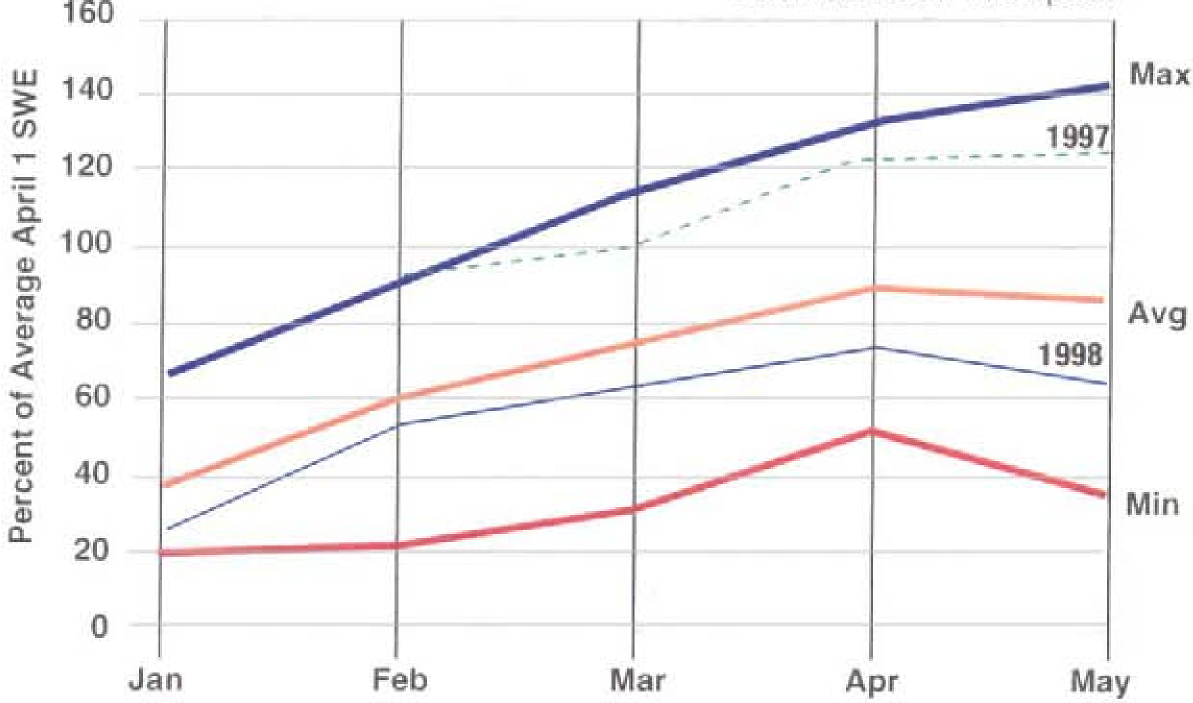
Chart 1
Seasonal Precipitation
Columbia River Basin
October 1997 - September 1998
Percent of 1961 - 1985 Average

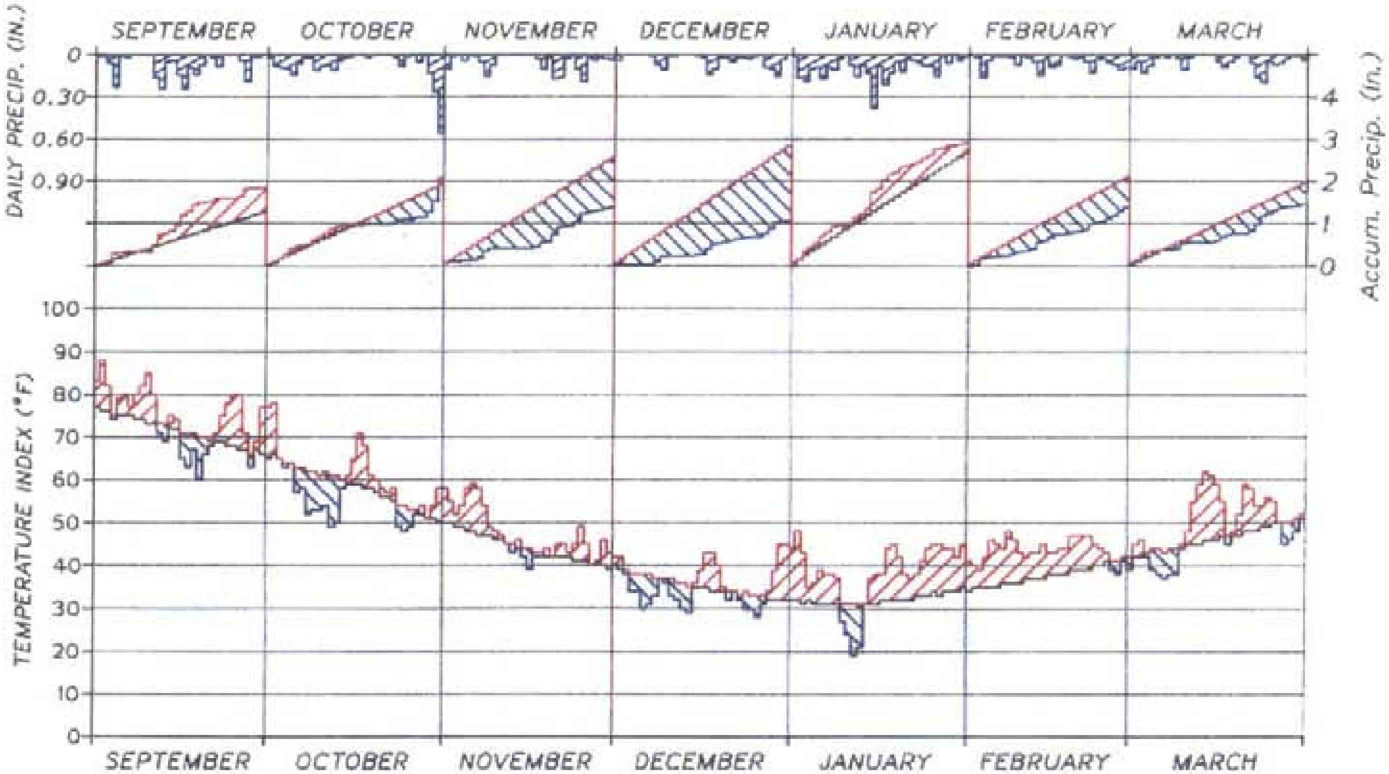


Information prepared by
NATIONAL WEATHER SERVICE
Northwest River Forecast Center
Portland, Oregon

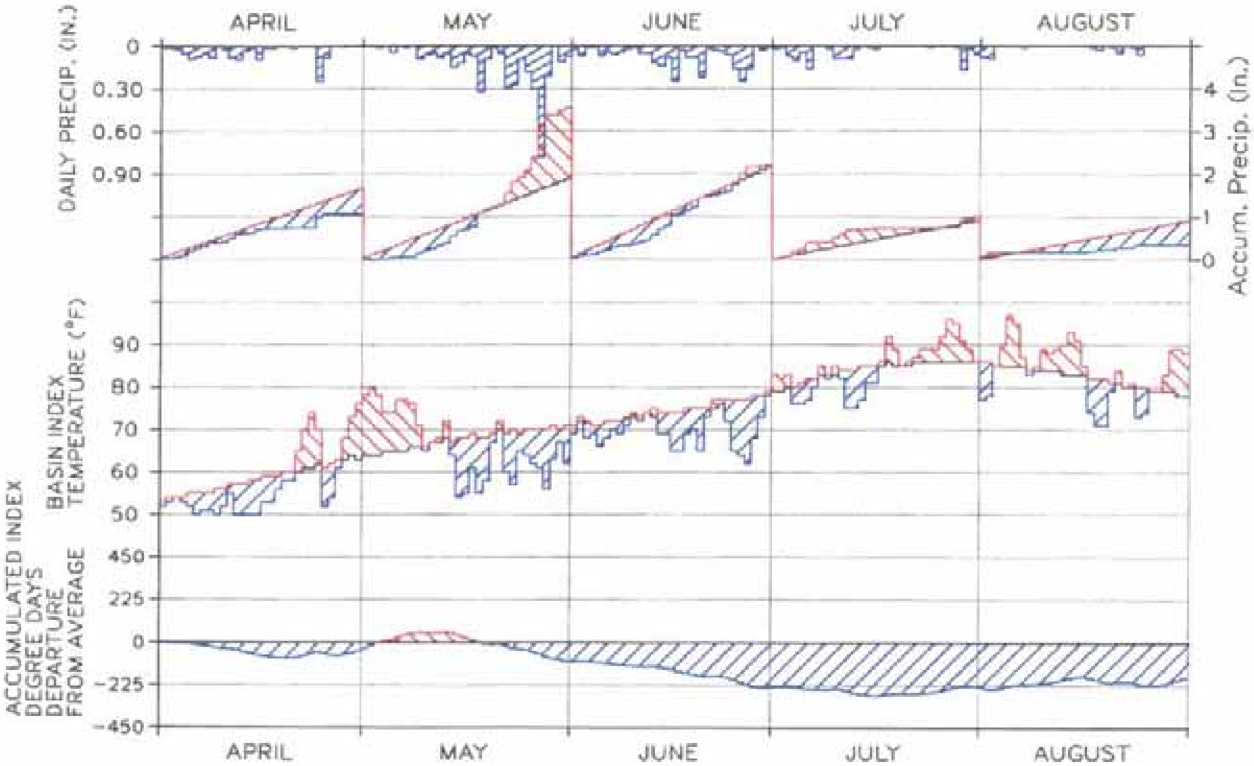
Chart 2

Columbia Basin Snowpack

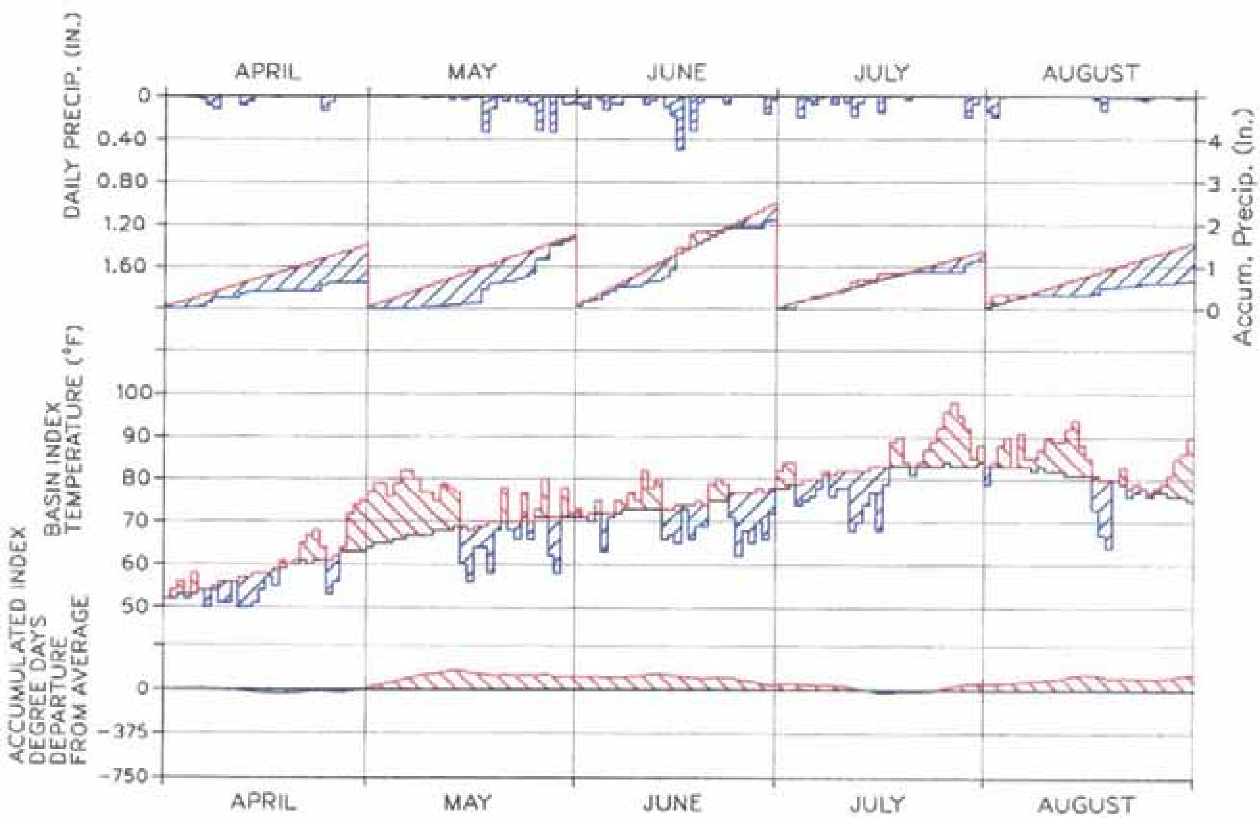




WINTER SEASON CHART 3
TEMPERATURE AND PRECIPITION INDEX 1997–1998
COLUMBIA RIVER BASIN ABOVE THE DALLES, OR

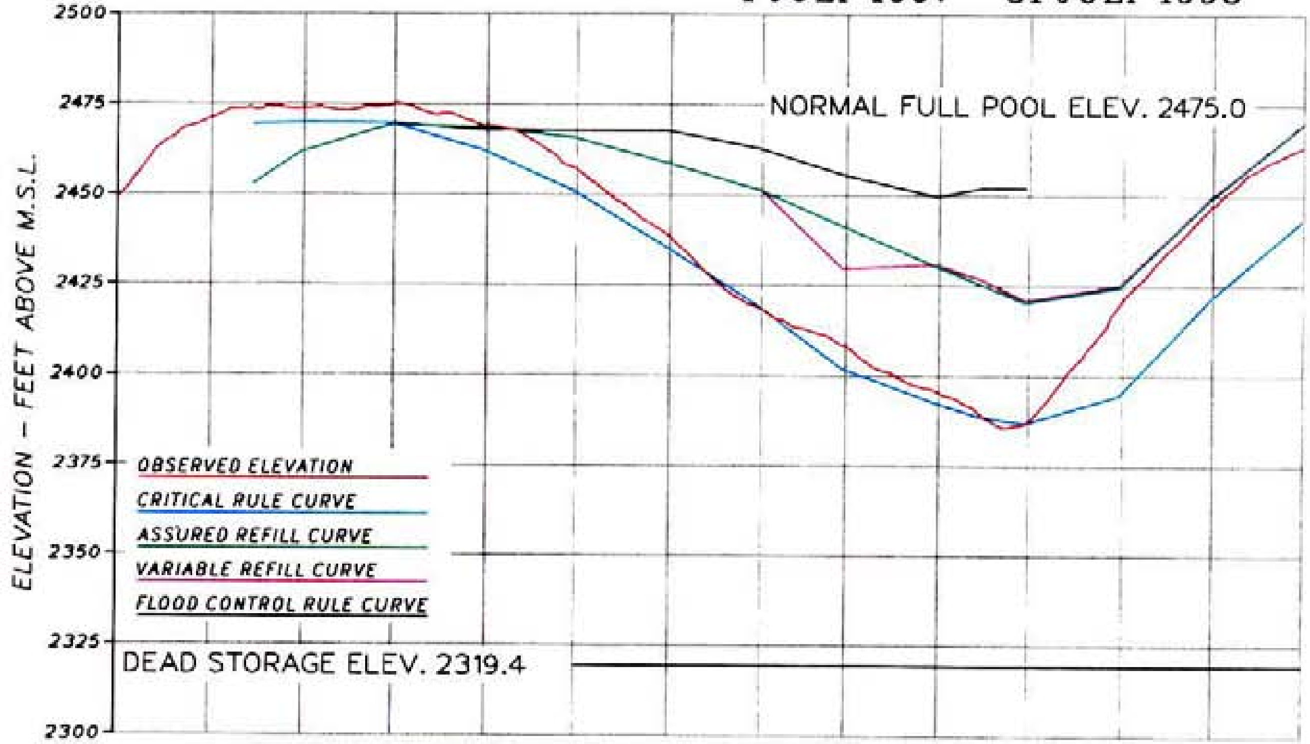


1998 SNOWMELT SEASON CHART 4
TEMPERATURE AND PRECIPITATION INDEX
COLUMBIA RIVER BASIN ABOVE THE DALLES, OR



1998 SNOWMELT SEASON Chart 5
TEMPERATURE AND PRECIPITATION INDEX
COLUMBIA RIVER BASIN IN CANADA

CHART 6
REGULATION OF MICA
1 JULY 1997 – 31 JULY 1998



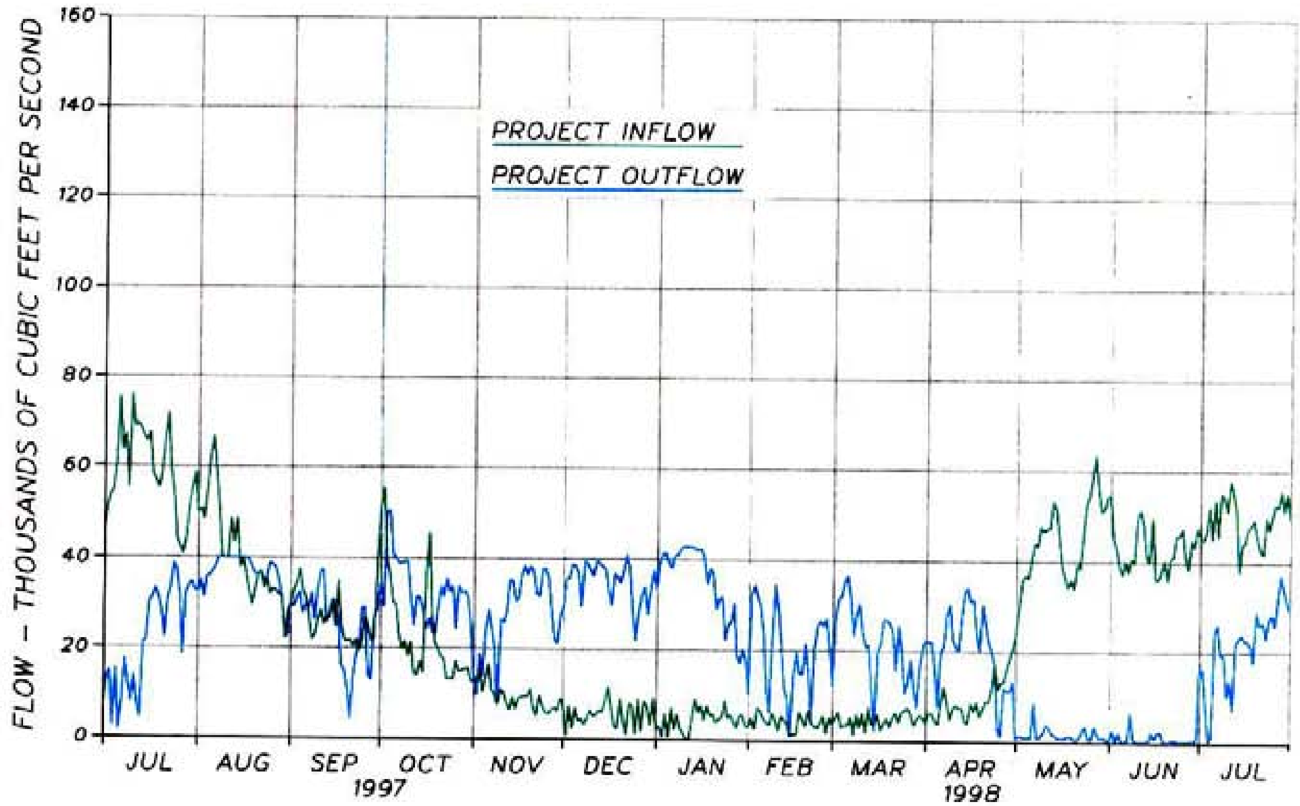
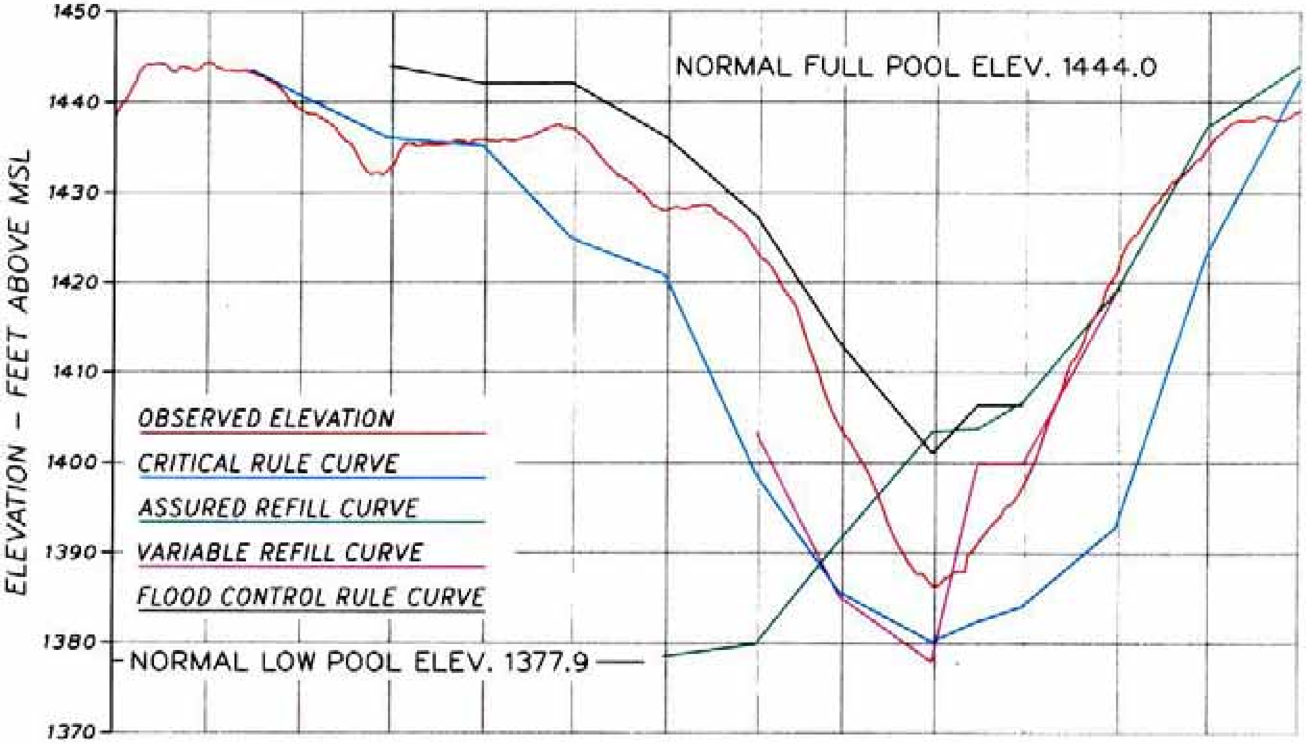


CHART 7
REGULATION OF ARROW
1 JULY 1997 - 31 JULY 1998



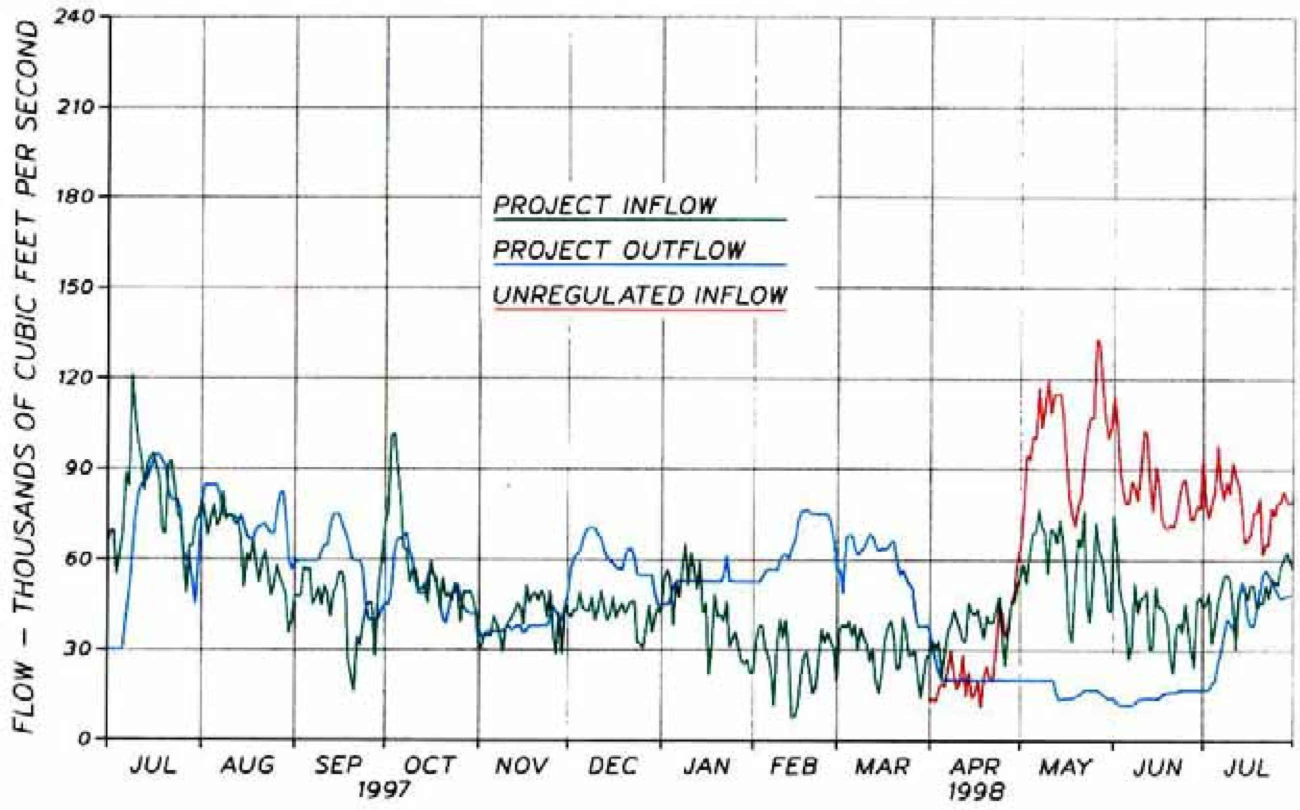
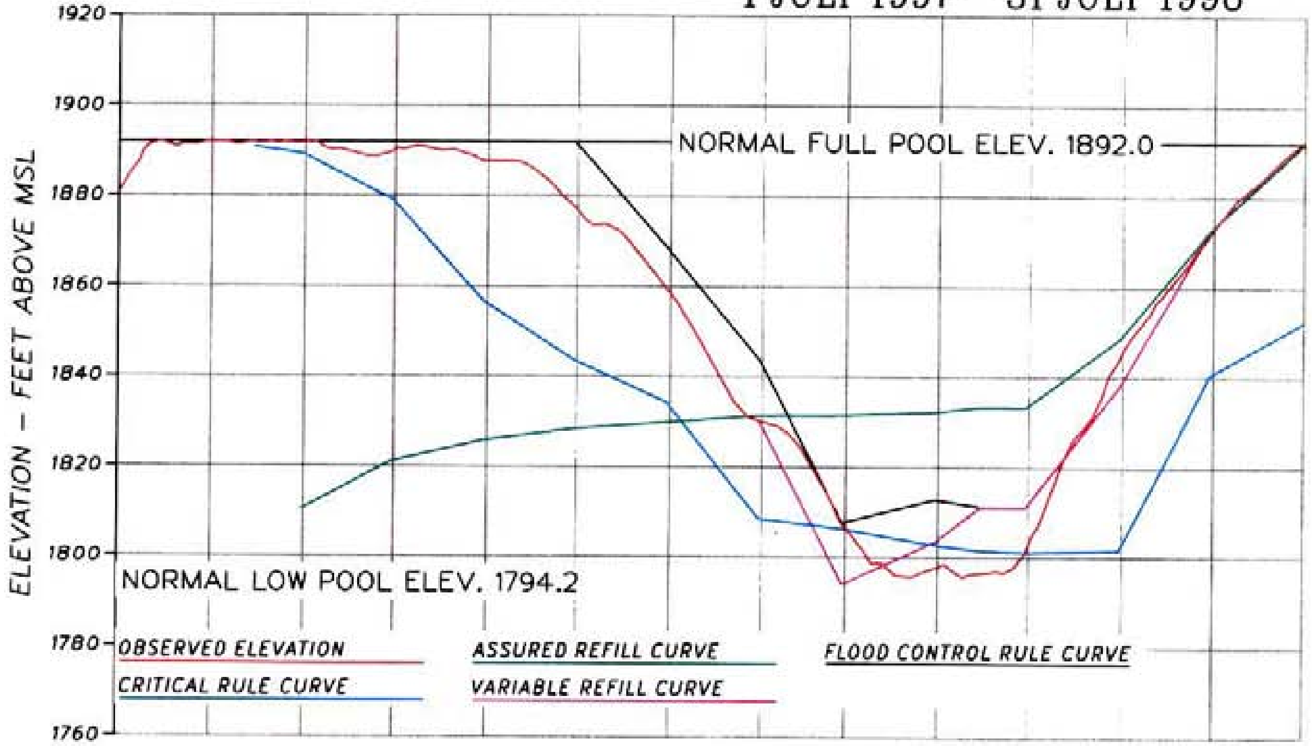


CHART 8
REGULATION OF DUNCAN
1 JULY 1997 – 31 JULY 1998



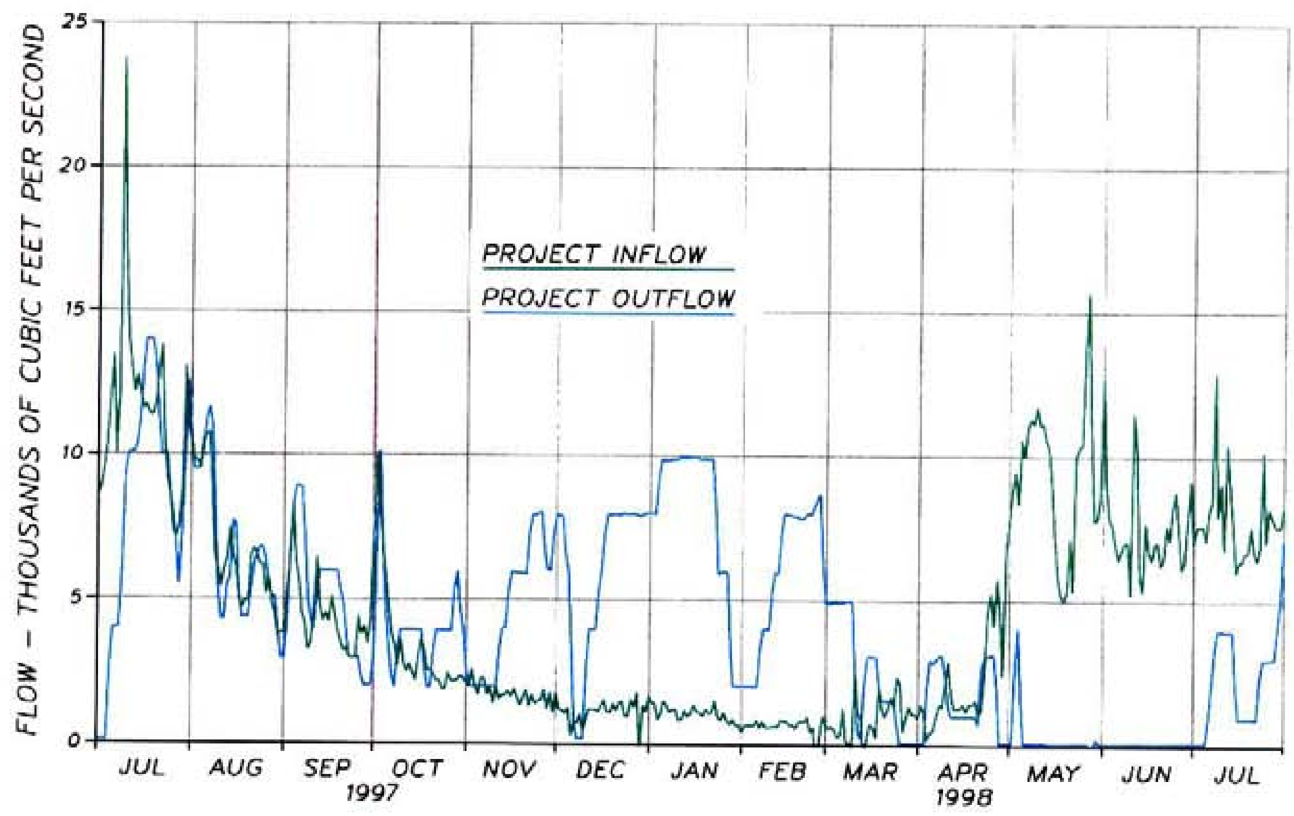
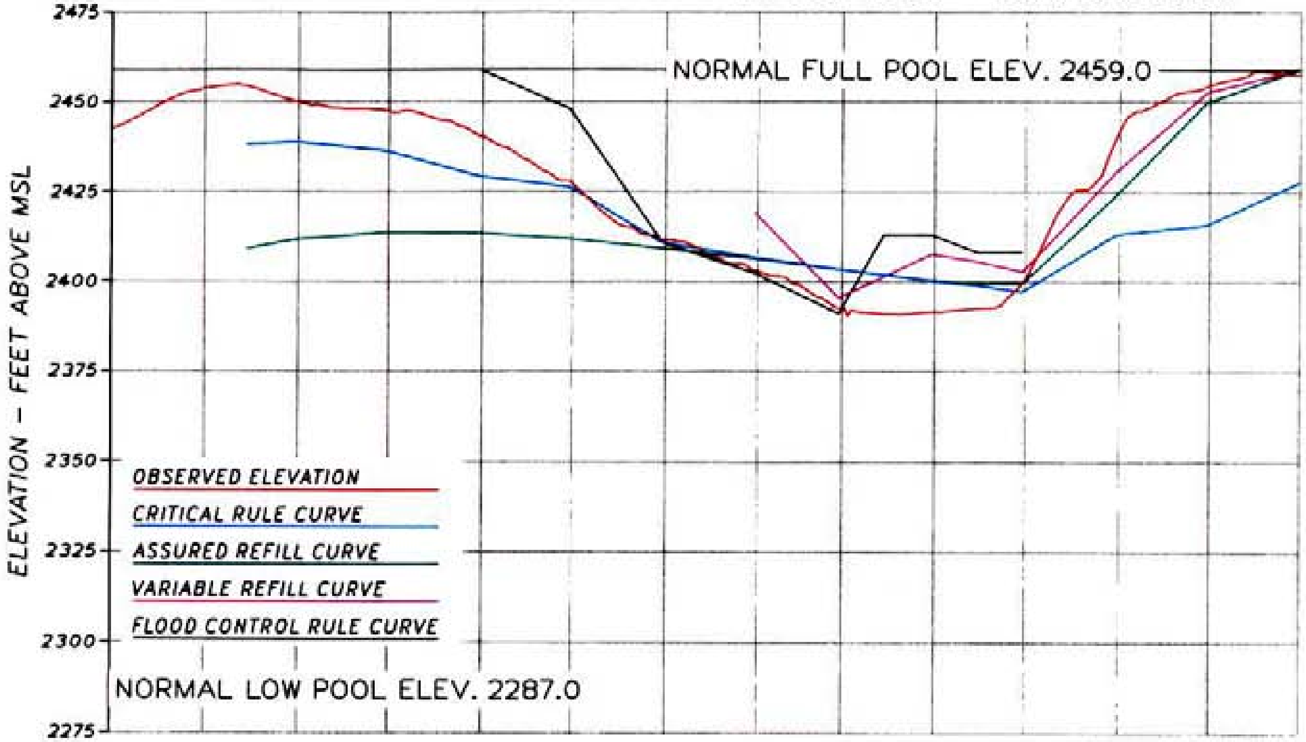


CHART 9
REGULATION OF LIBBY
1 JULY 1997 – 31 JULY 1998



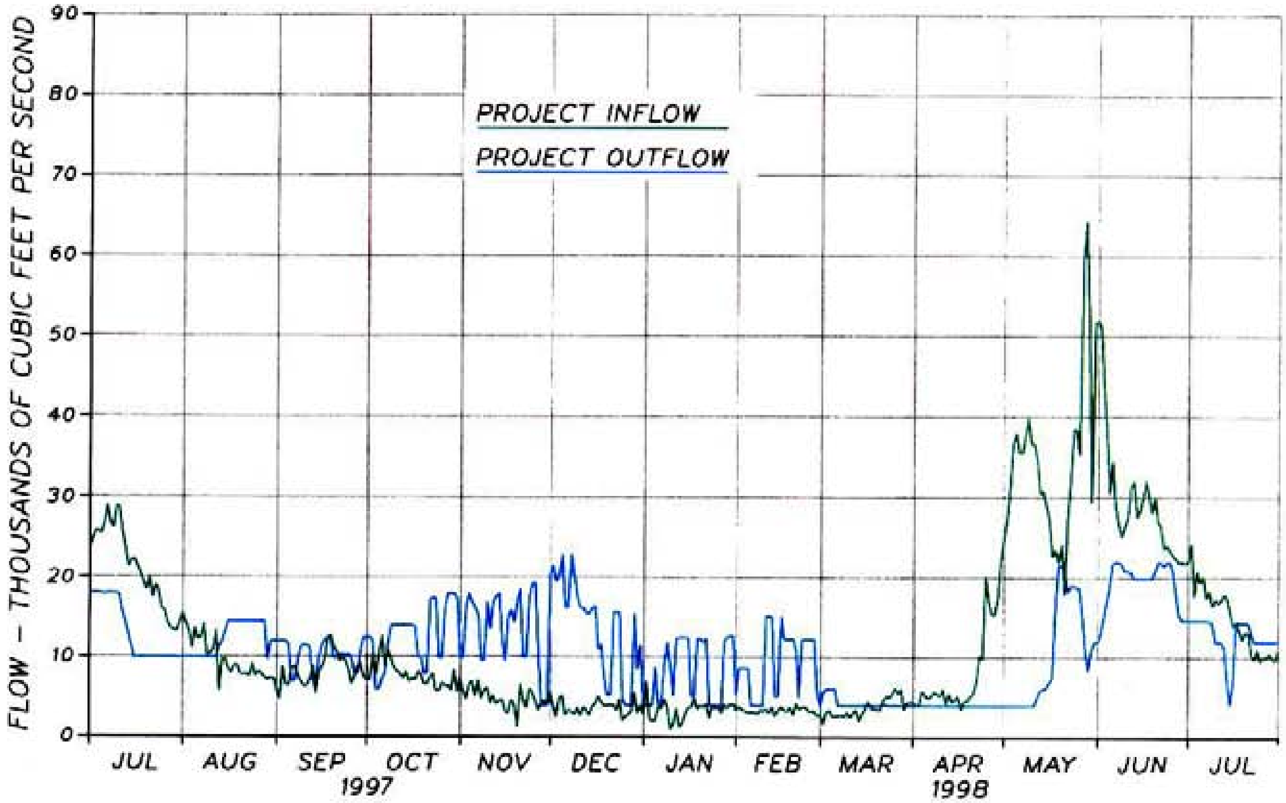
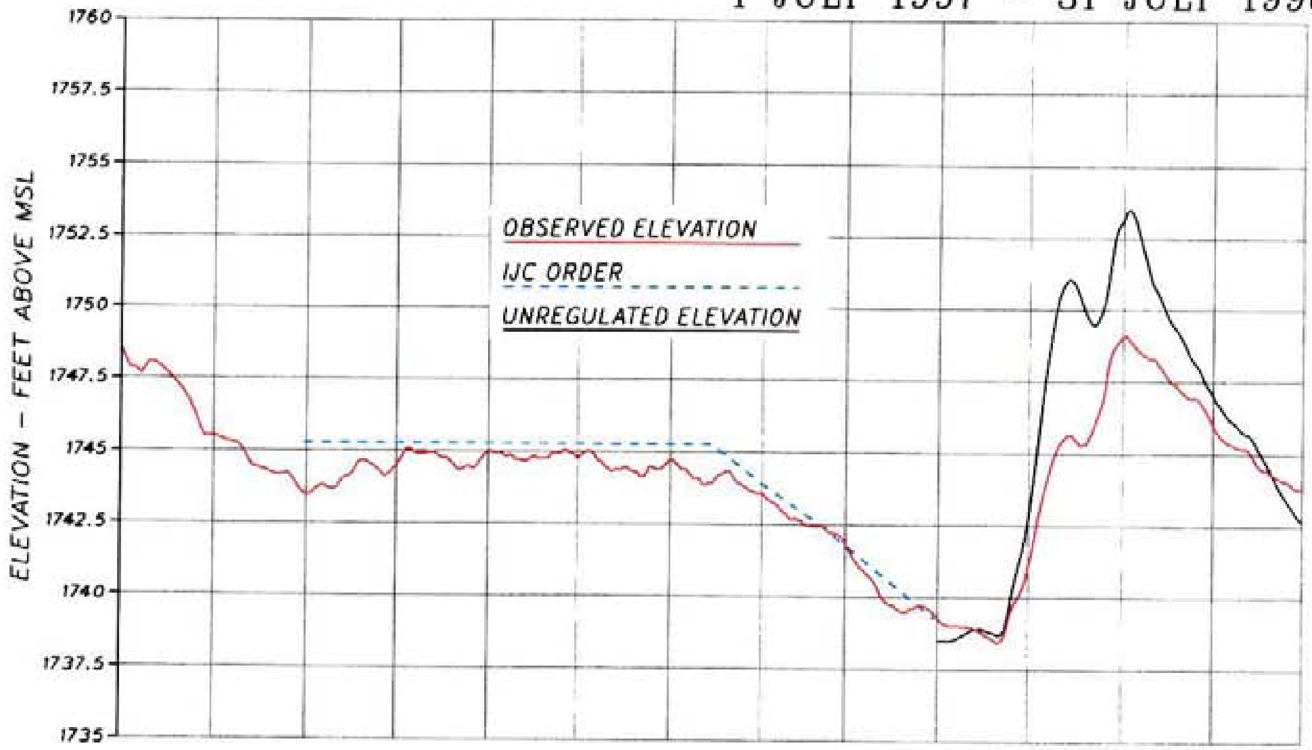


CHART 10
REGULATION OF KOOTENAY LAKE
1 JULY 1997 – 31 JULY 1998



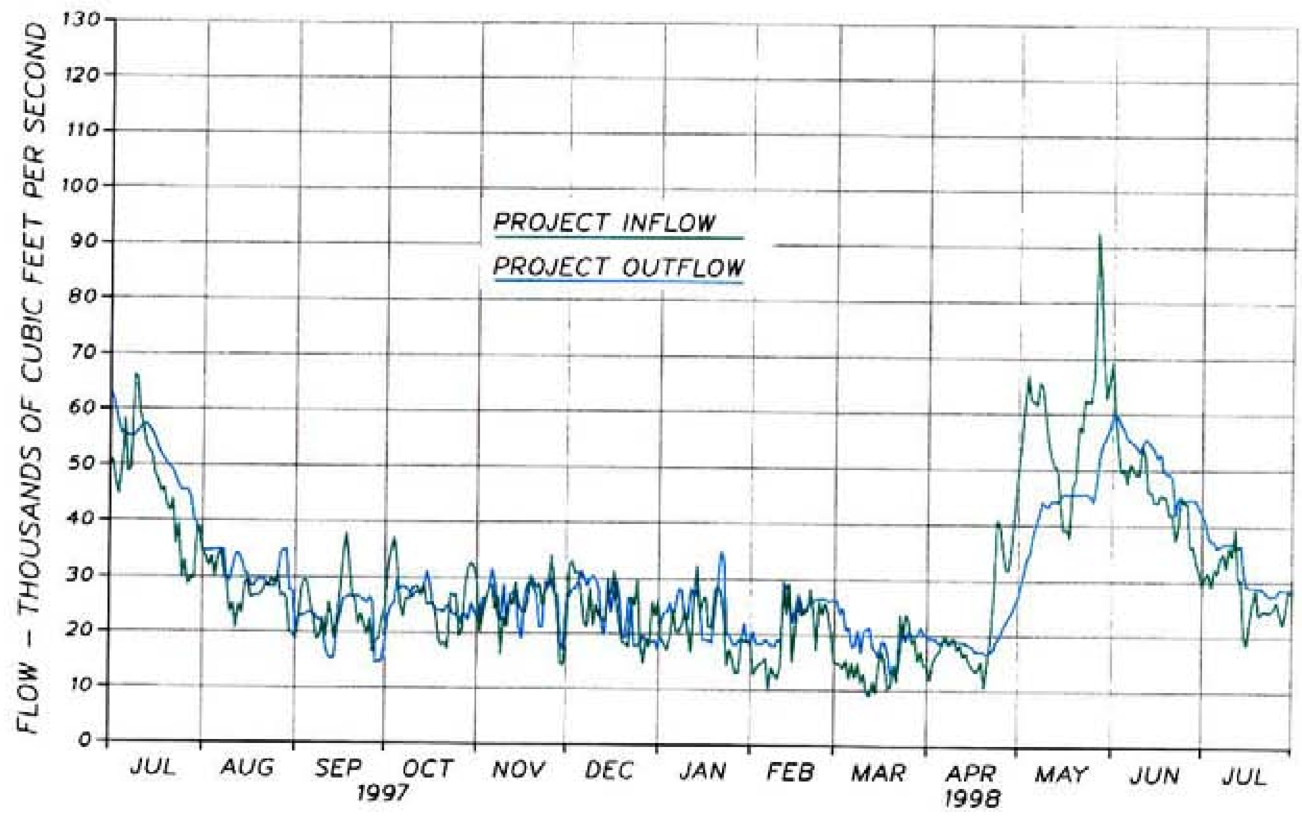


CHART 11
COLUMBIA RIVER AT BIRCHBANK
1 JULY 1997 - 31 JULY 1998

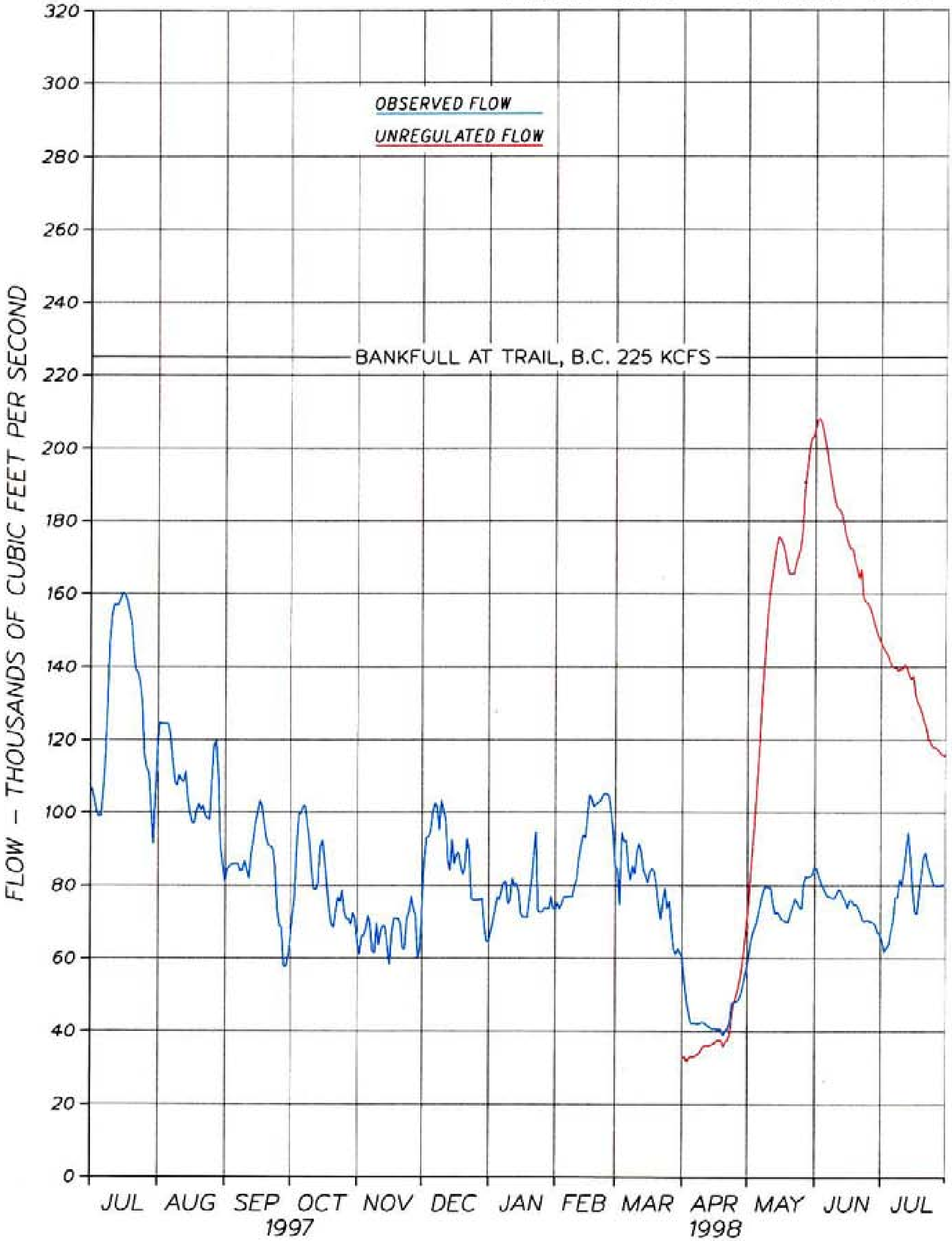


CHART 12
REGULATION OF GRAND COULEE
1 JULY 1997 - 31 JULY 1998

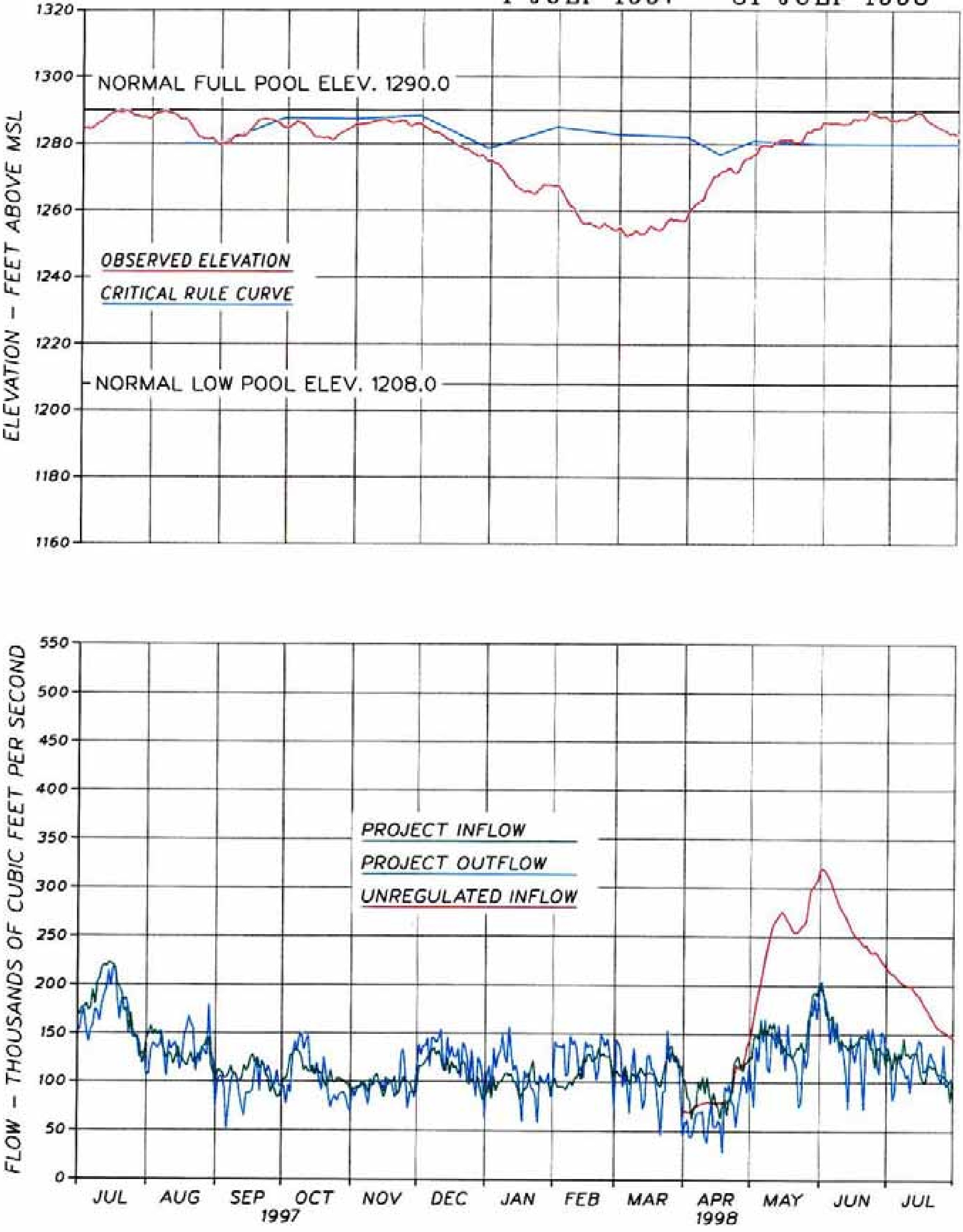


CHART 14
COLUMBIA RIVER AT THE DALLES
1 APRIL 1998 - 31 JULY 1998

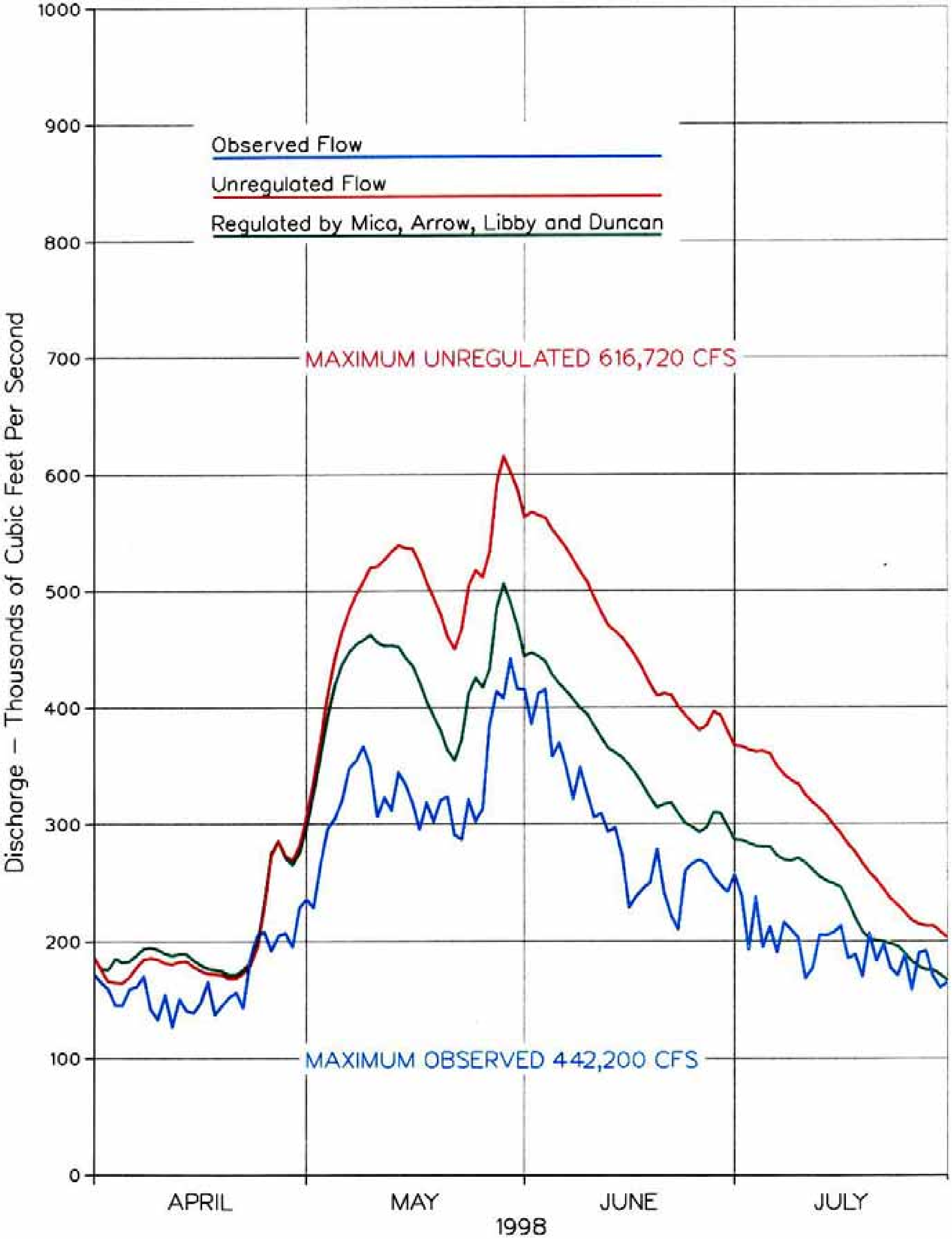


Chart 13
Columbia River at The Dalles
1 July 1997 - 31 July 1998

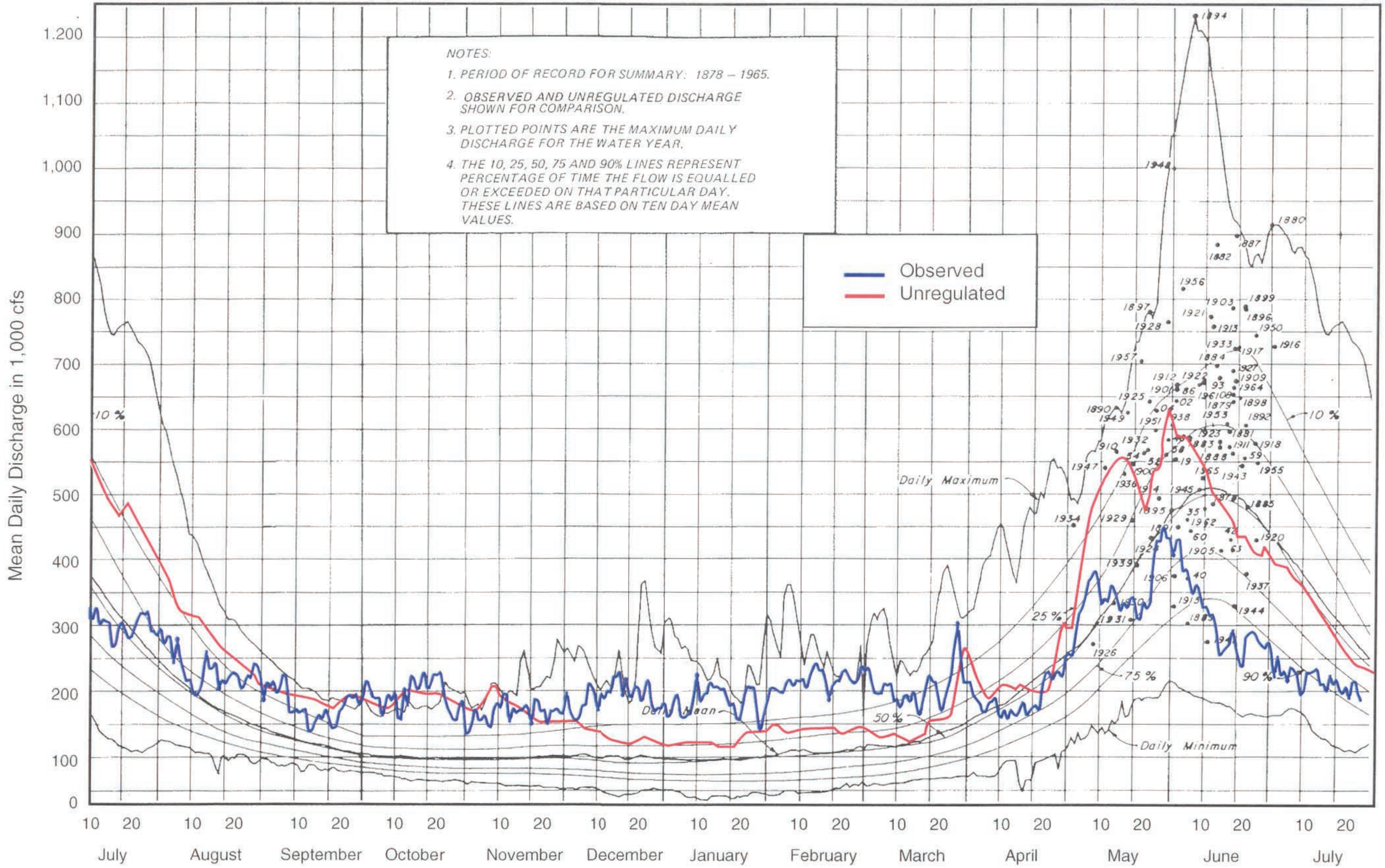


CHART 15
1998 RELATIVE FILLING
ARROW AND GRAND COULEE